Hydrogen and Fuel Cells: Pathway to a Sustainable Energy Future

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Main Thesis: hydrogen made from natural gas that is used in fuel cells can substantially improve our homeland security and reduce local pollution and greenhouse gas emissions while providing a pathway to an eventual sustainable energy future based on renewable hydrogen. However, private industry has little incentive to expeditiously implement a hydrogen and fuel cell energy system when the primary advantages –improved security and a cleaner environment-- accrue to society as a whole. This is the primary responsibility of government – to provide for the common good. Governments should therefore provide industry with the necessary incentives, both financial and regulatory, to develop these hydrogen energy systems that will benefit all society.

Key Hydrogen Infrastructure Conclusions:

A hydrogen infrastructure based on reforming natural gas at the fueling station for use in fuel cell vehicles would be less expensive than the existing crude oil-to-gasoline fueling system, with the potential to reduce global cumulative motor vehicle fueling infrastructure investment costs by US$ 840 billion to US$ 1.1 trillion over the next 40 years.

This distributed hydrogen infrastructure based on reforming natural gas at the local fueling station would also reduce global consumption of crude oil by 700 to 1,000 quads[1] over the next 40 years, as hydrogen-powered fuel cell vehicles replaced conventional light duty vehicles running on gasoline or diesel fuel. Natural gas consumption would increase by 500 to 700 quads over this same period. Therefore shifting to hydrogen made from natural gas would reduce net fossil fuel consumption by 200 to 300 quads over 40 years.

Using hydrogen made from natural gas would have minimal impact on natural gas resources even if renewable hydrogen did not materialize for 40 years. If 60% to 80% of all new cars sold were direct hydrogen fuel cell vehicles by 2030 and thereafter, and even if all the hydrogen came from natural gas, natural gas resources would be decreased by only 8% to 11% by 2040 compared to current projections. In addition, crude oil resources would be increased by 26% to 36% compared to a continuation of current motor vehicle technology without any fuel cell vehicles.

[1] One quad equals 10^{15} British Thermal Units (one quadrillion BTUs); for reference, the US consumed 38.6 quads of petroleum products in 2000, with total world oil consumption of approximately 155 quads per year. World natural gas consumption is approximately 90 quads per year, of which the US consumes 23.4 quads.

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1. Introduction and Long-Term Vision

Humankind must eventually find alternatives to burning fossil fuels to power our modern society. Fossil fuels will never run out, but their total societal cost will continue to increase in the future due to some combination of environmental damage including climate change impacts, local air and water pollution, scarcity, increasing difficulty of extraction and processing, and military costs to protect our crude oil lifeline to unstable regions of the world.

Fossil fuels will be the backbone of our energy system for at least several decades. But eventually society will have to move toward a sustainable energy system – an energy supply system that generates no pollution and consumes no non-renewable or exhaustible natural resources, at least during operation. While it may take many decades to transition to a predominately non-fossil fuel future, energy choices we make now can help implement or could impede progress toward society's long-term goal of energy sustainability. Given the choice between two energy options today that have approximately equal security and environmental benefits, we should lean toward those options that facilitate a transition to a truly sustainable energy future. Only two energy systems meet this strict definition of sustainability: nuclear fusion and renewable hydrogen.

1.1. Nuclear Fusion

Nuclear fusion --unlike existing nuclear fission plants-- would be sustainable, producing no air pollution or greenhouse gases in operation, and deriving all of its energy from sea water[2]. However, despite expenditures of hundreds of billions of dollars annually over several decades, scientists have yet to demonstrate breakeven, when the amount of energy into a test reactor equals the fusion energy generated. Even if scientific breakeven were demonstrated, there is considerable uncertainty whether engineers could ever build an affordable nuclear fusion power plant.

1.2. Renewable Hydrogen

This leaves renewable hydrogen as the only long-term sustainable energy option that is technically feasible today. In a renewable hydrogen system, all energy would come from either wind, solar, hydroelectric, biomass or municipal solid waste. With the exception of hydroelectric and more recently wind power, renewable energy is too costly today to compete with cheap fossil fuels, at least if total societal environmental, health and national security costs are excluded from the calculation of fossil energy price.

In this future sustainable energy system, renewable electricity would be consumed via the power grid (if available) whenever possible. However, renewable electricity has two deficiencies: it cannot be economically stored, and- barring any breakthrough in battery technology – electricity cannot be effectively used in the transportation sector[3] that currently accounts for almost 71% of all

[2] The primary fusion reaction combines deuterium and tritium, the isotopes of hydrogen. Deuterium can be obtained from seawater, and tritium can be generated in the fusion reactor by bombarding lithium with 14 MeV neutrons from the fusion reaction. Lithium in turn can also be extracted from seawater. See Appendix A for a brief description of the attributes of a fusion reaction.

[3] Battery-powered electric passenger vehicles have limited range due to the low energy density of existing and planned advanced batteries, and the time to recharge these batteries may also inhibit customer acceptance. With advanced lead acid batteries, modern EVs have ranges between 50 to 75 miles between charges. While adequate for commuter vehicles, most drivers are not willing to purchase vehicles with less range than current vehicles that can travel 300 miles

crude oil products consumed in the US. As intermittent renewables reached 20% to 25% of grid penetration in any region, then some type of storage would be required to save solar energy for later use when the sun was not shining or the wind was not blowing.

Hydrogen solves both problems as an energy carrier. Hydrogen gas can be stored indefinitely, and hydrogen can be used to provide power for virtually all transportation applications. A hydrogen-powered fuel cell 5-passenger vehicle has been designed (but not built – See Figure 1) that would have the full 380-mile range required under the PNGV program with passenger and trunk volumes and accelerations equal to those of conventional gasoline cars. In a renewable hydrogen future, then, hydrogen would complement electricity as a zero-emission energy carrier. The transportation sector would be powered almost exclusively by hydrogen, and hydrogen would also be used as a load-leveling energy storage system as needed for the electrical power grid.

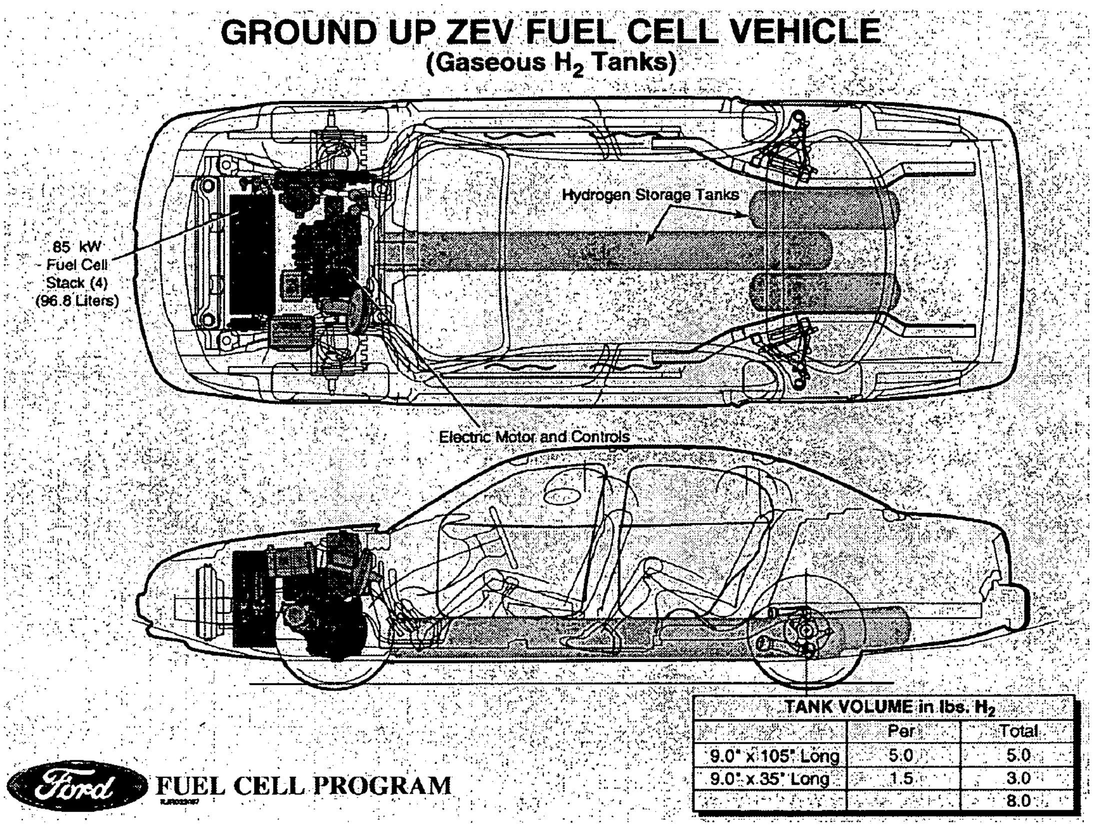

Figure 1. A conceptual fuel cell vehicle fueled with 5,000 psi hydrogen stored in carbon fiber-wrapped tanks

Since renewable hydrogen is generally too expensive to compete with cheap fossil fuel for the immediate future, we need an affordable, multi-decade transition strategy to move from sole dependence on fossil fuel to the renewable hydrogen end game. In our judgment, hydrogen made locally from natural gas can provide the necessary transition. Hydrogen derived from natural gas

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or more between fill-ups. New advances such as nickel metal hydride batteries can extend the EV range to 100 miles or more, but the added expense of these new batteries may deter most customers. And, of course, batteries are out of the question for air or ship transport.

will provide an immediate reduction in local air pollution and greenhouse gas emissions. We will show below that this transition strategy is affordable and will protect our environment and reduce our national security vulnerabilities better than the alternatives.

2. Homeland Security Considerations

The security and well being of the United States as we know it depends to a large degree on the continued functioning of our energy system. That security is threatened in part by our dependence on imported crude oil and could be in jeopardy in the future due to our reliance on a centralized electricity supply system with vulnerable transmission and distribution links.

2.1. Imported Oil

The transportation sector depends almost exclusively on gasoline and diesel fuel extracted from crude oil[4], more than half of which is imported to the US. Increasing the fuel economy of existing vehicles could reduce this dependence on imported oil, or it could be eliminated by switching to fuels derived from domestic natural gas or from renewable energy. However, over the last decade, automakers have chosen to increase the acceleration and power of passenger vehicles instead of increasing fuel economy, and attempts to convert to alternatively fueled vehicles have been marginal at best. The EPA reports that the average light duty vehicle fuel economy of 20.4 mpg (24.2 for cars and 17.3 for light trucks, including 22% SUVs) is now at its lowest point since 1980. At the same time that fuel economy has stagnated and slightly declined, average vehicle weight is up approximately10%, top speed is up 12%, and vehicle power is up 50% since 1980[5].

Technology such as hybrid electric vehicles (HEVs)[6] or fuel cell vehicles (FCVs) could improve fuel economy by 50% to 250% over existing gasoline internal combustion engine vehicles (ICEV). However, the EIA projects that fuel economy of the light duty fleet will increase only slightly over the next twenty years, from 19.8 mpg in 2000 to 21.0 mpg in 2020[7]. At the same time vehicle miles traveled are projected to increase from 2.3 billion miles to 3.6 billion miles, an increase of 57%. As a result, the EIA predicts that energy consumption in the transportation sector will increase by 44%, from 27.3 quads in 2000 to 39.4 quads in 2020. If all of this energy were still derived from crude oil in 2020, our dependence on foreign oil would continue to grow, decreasing our security and further imperiling our environment over time.

The best interim approach to reducing our dependence on imported oil would be to convert to a fleet of direct hydrogen FCVs powered by hydrogen derived from natural gas. This option totally cuts our ties to crude oil. Hydrogen would come primarily from natural gas produced in North America. Initially some FCVs might be powered by hydrogen produced by electrolysis of water, using grid

[4] The EIA estimates that 97% of all transportation energy is derived from crude oil products, Table A2 of the Annual Energy Outlook 2002.
[5] Ponticel, Patrick, "EPA says fuel economy hits 21-year low," *Automotive Engineering International,* November 2001, pg. 112.
[6] An HEV is defined here as a vehicle with electric motors, a storage battery and a small internal combustion engine that can drive the wheels directly or can be coupled to a generator to recharge the battery (the parallel hybrid mode.)
[7] Op. cit, EIA, Table A7.

electricity as the primary source of power[8]. This electrolytic hydrogen would also be nearly free of any connection to imported oil[9].

2.2. Central Power Grid Vulnerability

The tragic events of September 11 have shocked our nation into reassessing other vulnerabilities of our modern society. The electrical power grid is particularly vulnerable, both in terms of huge central power plants, and also the fragility of the grid distribution system. Destruction of a few key nodes in the transmission network could black out large regions of our nation.

Even before September 11, distributed power generation was seen as an economically attractive alternative to building more central power plants with their long construction times and huge capital outlays. Small generators located near or on the customer's property can avoid the need for costly transmission and distribution investments. Many customers are adding their own power generation capacity in any case to improve reliability – to provide assured power for sensitive industries that may lose millions of dollars a minute with every electricity disruption. Dispersing electrical power generation will also reduce total system vulnerability. Stationary fuel cell systems running on natural gas offer one of the best options for simultaneously reducing electrical grid vulnerability while cutting pollution.

3. Environmental Considerations

While September 11 has dramatically escalated our concerns over homeland security, any new energy system must also be environmentally sound, both with respect to local air and water pollution as wells as global greenhouse gas emissions.

3.1. Local Air Pollutants

The California zero emission vehicle (ZEV) mandate requires that 2% of all vehicles offered for sale by 2003 emit zero criteria pollutants (VOCs, NOx and CO)[10]. The state Air Resources Board (ARB) has also stipulated that beginning in 2003 the large transit districts should demonstrate three zero-emission buses each. By 2008, 15% of all new buses must be zero-emission buses. Hydrogen-powered FCVs and battery-powered electric vehicles (BPEVs) are the only two options that meet the strict ZEV standard. The range and refueling time of BPEVs are generally unacceptable for most applications. Advanced batteries can increase the range between charges from 50 miles to 100 miles or more, but only with increased cost. As discussed above, a direct hydrogen FCV can have the full range and acceleration of traditional passenger cars. Thus the direct hydrogen FCV is the only practical option for meeting the true ZEV mandate.

3.2. Greenhouse Gas Emissions

Direct hydrogen FCVs are true ZEVs, producing no local emissions, but the total well-to-wheels greenhouse gas (GHG) emissions depend on the source of the hydrogen. Figure 2 shows the results

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[8] Using grid electricity to electrolyze water to produce hydrogen does have one very serious drawback: greenhouse gases would increase dramatically compared to gasoline in conventional cars, since most electricity in the US comes from burning coal. See Section 3.2 below.

[9] Approximately 2.5% of all US electricity is generated by burning fuel oil.

[10] The ZEV mandate applies to 10% of all new vehicles offered for sale, but the regulation was previously watered down with partial credits for very low emitting vehicles such as methanol or gasoline FCVs and some qualifying HEVs, such that only 4% had to be true ZEVs. More recently, this 4% true ZEV goal was reduced to 2%. The CARB did increase the overall 10% mandate up to 16% in 2018.

of vehicle simulations for 5-passenger FCVs, including direct hydrogen FCVs and FCVs with onboard fuel processors to convert gasoline or methanol into hydrogen. The GHGs for a conventional vehicle are shown on the left side bar for comparison. All GHGs are included in these projections, with the non-CO_2 GHGs converted to equivalent CO_2 emissions based on a 100-year atmospheric dwell time.

Greenhouse gases can be virtually eliminated if the hydrogen were generated by renewable sources such as PV, wind, biomass or hydroelectricity. This is the ultimate goal of the hydrogen economy. In the meantime, while renewable energy system costs are being reduced, the second best approach to cutting GHGs is to make the hydrogen from natural gas and store it onboard the vehicle as a compressed gas. Hydrogen from natural gas used to power a FCV would cut GHGs by approximately 40 to 45% compared to a gasoline-powered ICEV as shown in Figure 2. If hydrogen were liquefied at any point in the fuel cycle, then there would be negligible GHG advantage. The electricity required for the liquefaction process, most of which comes from burning coal in the U.S., would cancel the effects of increased FCV efficiency. Finally, if the hydrogen were generated by electrolysis of water using grid electricity based on the marginal grid mix averaged across the U.S., then the GHGs would be more than doubled compared to current gasoline-powered cars, even though the hydrogen was used in a pristine, zero emission FCV. The two bars on the right side of Figure 2 show the estimated GHGs for methanol and for gasoline-powered FCVs. Two estimates are made for these vehicles, given the uncertain performance of onboard fuel processing technology still under development.

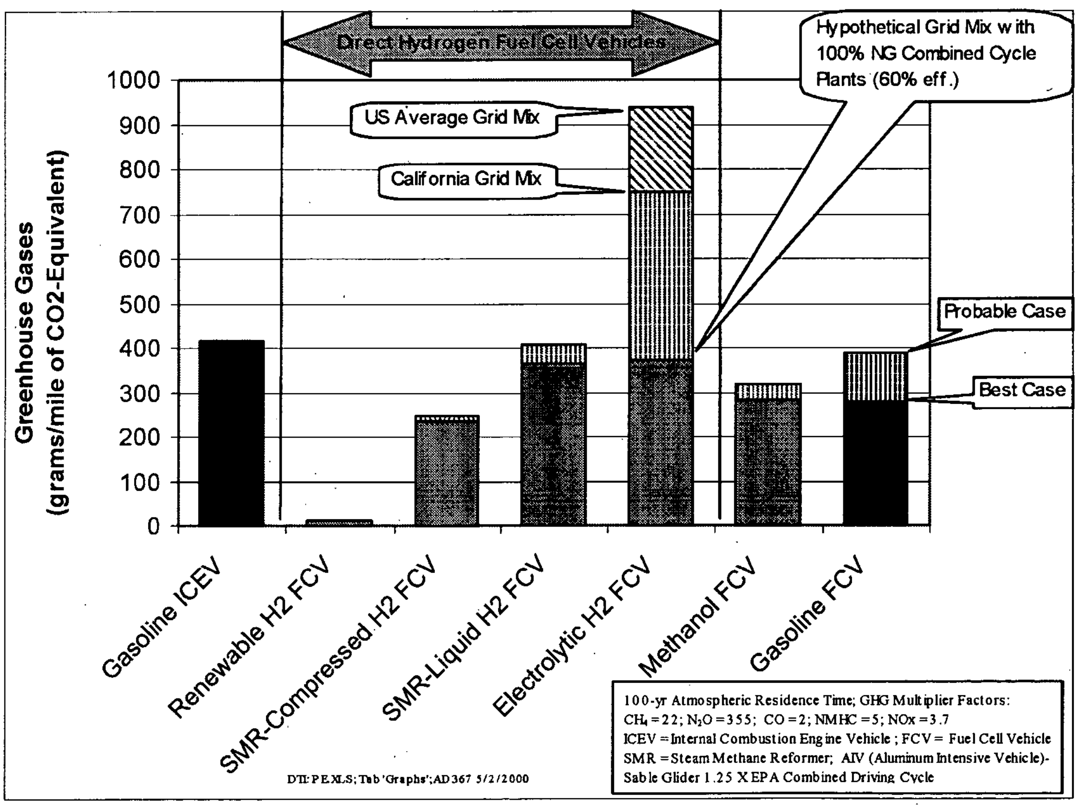


Figure 2. Total "well-to-wheels" greenhouse gas emissions for various fuel cell vehicles compared to gasoline internal combustion engine vehicles

In summary, the direct hydrogen FCV with compressed hydrogen onboard storage and hydrogen derived from natural gas at the fueling station provides the best reduction in GHGs compared to other FCV fueling options (assuming that renewable hydrogen is too expensive at this time).

4. Perceived Obstacles to Hydrogen-Powered Fuel Cell Vehicles

Despite all of the advantages of a hydrogen-based fuel cell economy, some analysts are concerned that hydrogen-powered fuel cell transportation systems may not be viable for many years, if ever. The three most common perceived hurdles to the widespread development of hydrogen-powered fuel cell vehicles include:

- Difficulty of onboard hydrogen storage
- Lack of and estimated cost of a hydrogen fuel infrastructure system, and
- Perceived safety concerns regarding hydrogen gas

4.1. Onboard Hydrogen Storage

Hydrogen gas is very diffuse, requiring more volume than gasoline or natural gas to store a given quantity of energy. Hydrogen can be stored as a compressed gas, a cryogenic liquid (at –253°C or 20°K), or hydrogen can be stored in metal or chemical hydride materials[11]. In our judgment, the best option today is to compress hydrogen to at least 5,000 psi (340 atmospheres or 34.5 MPa) and store the hydrogen in carbon fiber-wrapped composite tanks[12]. The carbon fiber provides extraordinary strength. These tanks, developed by the aerospace industry and used commercially to store compressed natural gas on vehicles, are so strong that they have been shown to survive simulated rear-end collisions up to 50 mph without losing any pressure[13]. At least two vendors, Quantum Technologies and Dynetek, have qualified 5,000-psi tanks for use in motor vehicles in North American, Japan and Europe.

Even with compression to 5,000 psi, however, a compressed hydrogen tank would require approximately 9.6 times as much volume as a gasoline tank for the same quantity of energy[14]. Fortunately, the FCV does not need as much energy as a gasoline ICEV. Detailed vehicle simulations show that a 5-passenger direct hydrogen FCV would have approximately 2.2 times higher energy efficiency than a conventional car of the same size and aerodynamic shape, based on the lower heating values of hydrogen and gasoline. This reduces the fuel tank storage volume factor to 4.4– the compressed hydrogen tank would need to be 4.4 times larger than a gasoline tank for the same vehicle range. However, comparing just fuel storage volumes does not provide the full picture. A FCV would replace the internal combustion engine, catalytic converter system,

[11] Researchers are also developing more exotic hydrogen storage mechanisms, including storing hydrogen in carbon nanofibers. Initial laboratory results at Northeastern University indicated extraordinary storage potential, such that one gasoline tank size of these carbon nanofibers could have provided several thousand miles range for a hydrogen FCV. However, these laboratory results have not been reproduced consistently, despite several years of efforts by several dozens of organizations around the world.

[12] Some automakers are suggesting even higher pressures, and Quantum and Thiokol are now developing 10,000 psi tanks for the DOE.

[13] In these tests pressurized tanks were placed in the trunks of old cars. The cars were then hoisted by a crane and dropped from various heights, including a drop from 92 feet that provided a terminal crash velocity of 52 mph.

[14] James, Brian D., George N. Baum, Franklin D. Lomax, Jr., C. E. (Sandy) Thomas and Ira F. Kuhn, Jr., "Comparison of Onboard Hydrogen Storage for Fuel Cell Vehicles," Task 4.2 Final Report under subcontract 47-2-R31148, prepared for the Ford Motor Company under DOE contract DE-AC02-94CE50389, May 1996.

transmission, fuel tank and related components of a conventional car with electric motors, the fuel cell stack, hydrogen tanks, inverter and power control electronics and related components for humidification and air pressurization. The appropriate question is whether all of these FCV components can be placed in a motor vehicle without encroaching into the passenger or trunk space.

Ford engineers designed (but did not build) the conceptual fuel cell 5-passenger vehicle shown in Figure 1 above. This FCV would have the same range, acceleration, and passenger and trunk space as a conventional gasoline vehicle. The hydrogen tanks are larger than the corresponding gasoline tanks, but this design illustrates that these tanks can be accommodated in a five-passenger FCV. Better designs are surely possible with a "clean-sheet" FCV design based on compressed hydrogen tanks and fuel cells from the start. If companies do succeed in developing 10,000-psi tanks, then the hydrogen tank volume in Figure 1 could be reduced by another 40%.

4.2. Hydrogen Infrastructure Options

Most hydrogen used by industry is made in large steam methane reformers that convert natural gas to hydrogen. Generating hydrogen in these large central plants minimizes the cost of production. For the oil and chemical plants that need large quantities of hydrogen onsite to make ammonia for fertilizer, methanol, or to help convert crude oil to gasoline, central production makes good economic sense.

However, central production may not be the most economic pathway for fuel cell vehicles or for distributed electrical generation using stationary fuel cells. For either distributed application, the costs of hydrogen transportation are significant. Hydrogen produced at a central plant must either be pressurized and delivered by tube trailer or by hydrogen pipeline, or the hydrogen could be liquefied and shipped in cryogenic tanker trucks. Either option increases hydrogen delivered costs dramatically. For compressed hydrogen, gas companies might build a national pipeline system analogous to the existing natural gas pipeline infrastructure to supply FCVs anywhere in the country. Such a national pipeline system might cost hundreds of billions of dollars, which some analysts cite as proof that hydrogen could not be cost effective. A less expensive alternative would be to build more moderately sized hydrogen plants in each region, with shorter hydrogen pipelines to a cluster of nearby hydrogen fueling stations[15]. For liquid hydrogen, costly liquefaction equipment developed for the space program must be added to the hydrogen production equipment, and 30% to 35% of the energy content in the hydrogen must be used in the form of electricity to liquefy hydrogen, adding more cost. Each fueling station would then need insulated cryogenic tanks to keep the hydrogen at –253°C or 20°K.

We have previously shown under subcontract to the Ford Motor Company and their contract with the DOE to develop hydrogen-powered fuel cell vehicles that hydrogen could be made more economically at the local fueling station rather than at large central plants[16]. In this scenario, small-scale fuel processors such as steam methane reformers are mass-produced and placed at each fueling station or fleet operator's garage. While the cost of hydrogen production is higher than from a central plant, there is no additional cost for hydrogen transportation. The net delivered cost of

[15] Suggested by Dave Nahmias, December 20, 2001.

[16] Thomas, C. E., B.D. James, I.F. Kuhn, Jr., F. L. Lomax, Jr., and G. N. Baum, "Hydrogen Infrastructure Report," prepared by Directed Technologies, Inc. for the Ford Motor Company under DOE contract DE-AC02-94CE50389, July 1997 and "Affordable Hydrogen Supply Pathways for Fuel Cell Vehicles, *Int. J. Hydrogen Energy* (23), pp. 507-516, 1998.

hydrogen is less for these onsite hydrogen fueling appliances, as shown in Figure 3. In fact, our projections show that hydrogen made onsite from natural gas and used in a FCV would cost approximately the same per mile driven as wholesale gasoline in a conventional car. In effect we are substantially reducing the cost of a distributed hydrogen generation system by using the existing natural gas pipeline network as the main fuel infrastructure.

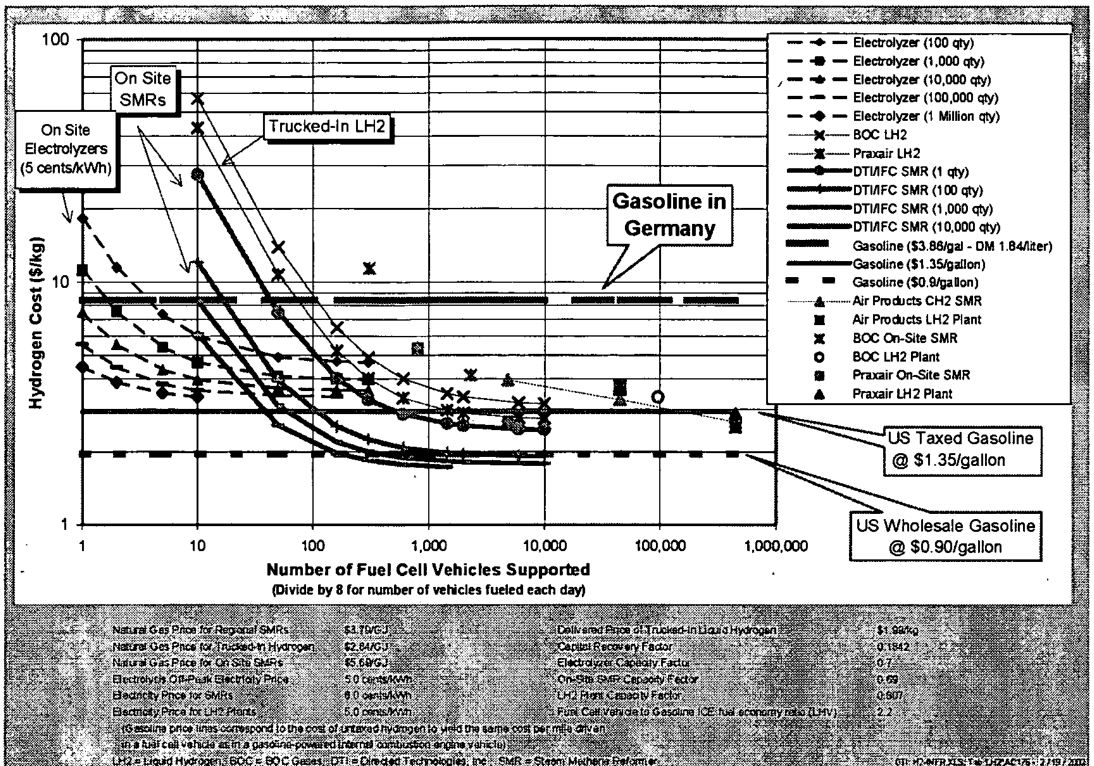


Figure 3. Estimated cost of compressed hydrogen delivered to fuel cell vehicles as a function of the production plant size

The horizontal lines in Figure 3 correspond to the price of hydrogen necessary such that the fuel cost per mile in a direct hydrogen FCV costs the same per mile as gasoline in a conventional car of the same size. Thus hydrogen costing approximately $2/kg would be equivalent to gasoline at $0.90/gallon, roughly equivalent to the wholesale price of gasoline, excluding highway taxes.

The large central hydrogen plants (indicated by the symbols on the right side of the chart) could be competitive with fully taxed gasoline at $1.35/gallon (assuming no highway taxes for hydrogen), assuming that the plant was located within 30 miles of a large set of hydrogen fueling stations. Liquid hydrogen would also be competitive with gasoline at $1.35/gallon for large fueling stations. As the fueling capacity at the station decreases, however, the cost per kg increases as shown by the curves labeled "Trucked-In LH2".

Our analyses show that hydrogen produced onsite (curves labeled "On Site SMRs") would be competitive with wholesale gasoline for stations supporting more than a few hundred FCVs as long as more than 100 to 1,000 hydrogen fueling appliances were manufactured. An average gasoline station refuels about 175 cars per day. Since each car refuels on the average every 8 days, this size

station would support 1,400 ICEVs. As shown in Figure 3, at this production level, the onsite reformer would be competitive with gasoline at rather modest production levels above 100 units. Thus, even if highway taxes were eventually added to hydrogen in a mature FCV marketplace, hydrogen would be competitive with gasoline.

This distributed hydrogen infrastructure has one other significant advantage over central production plants: the distributed hydrogen fueling appliances can be added gradually when and where they are needed to support an evolving FCV market. Investments can be gradual, matched to the need. The gas industry does not have to make billion dollar investments in advance on the hopes that FCVs will then materialize. Fueling appliances can be added for single fleets of one or two fuel cell buses or 160 FCVs.

The hydrogen costs for onsite natural gas reforming in Figure 3 assume that natural gas is purchased at commercial rates of \$6/MBTU (\$5.69/GJ) on a higher heating value basis. As shown in Figure 4, commercial rates in the US have averaged near \$6/MBTU, with the exception of the huge surge in gas prices in the January 2001 time period. However, natural gas prices have since fallen close to their historical averages. Note that industrial natural gas prices have been and currently are below \$4/MBTU.

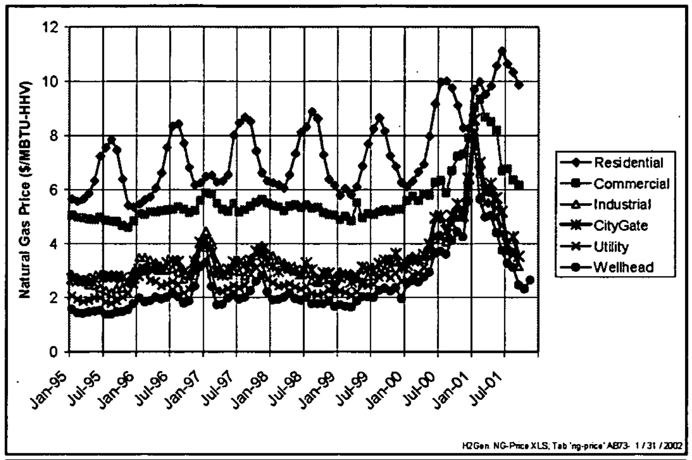


Figure 4. Average US natural gas prices 1995-2002

If energy companies could acquire industrial rates for a set of aggregated hydrogen fueling stations, then hydrogen prices could be even lower. For example, Figure 5 shows the same data as Figure 3, but with the natural gas price paid by the local fueling station reduced from \$6/MBTU to \$4/MBTU and natural gas reduced from \$3/MTBTU to \$2/MBTU at the large central plant. In addition we reduced the cost of off-peak electricity from 5 to 3 cents/kWh.

In this case the hydrogen made locally from a mature HFA supporting 1,440 FCVs would cost only \$1.36/kg compared to \$1.73/kg in Figure 3. This \$1.36/kg hydrogen cost corresponds to gasoline at \$0.69/gallon, assuming the 2.2 times improve fuel economy of the FCV compared to a conventional gasoline car. With this lower natural gas price, a FCV with a 66-mpgge fuel economy would still be competitive with a hybrid electric vehicle (HEV) with, for example, 50-mpg fuel economy: the hydrogen price would then be equivalent to gasoline in the ICE HEV at \$1.04/gallon.

From another perspective, the delivered cost of natural gas per unit energy is much less than the delivered cost of gasoline, as shown in Figure 6. We show both retail gasoline prices (including road taxes) and wholesale gasoline prices, compared to industrial and commercial natural gas prices. Making hydrogen from natural gas starts with this cost advantage when competing with gasoline as a transportation fuel. Initially hydrogen would not be taxed as a super-clean fuel. In a mature market, hydrogen would have to compete with fully taxed gasoline.

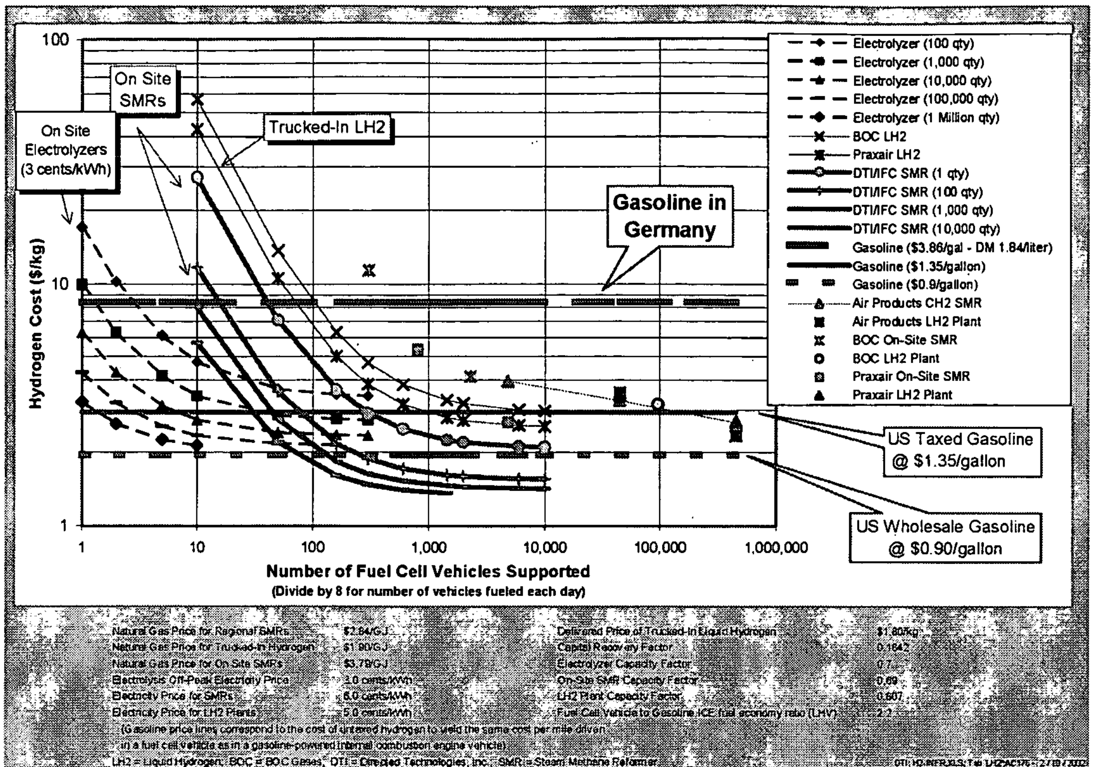


Figure 5. Estimated hydrogen costs for lower cost natural gas (\$2/MBTU central station; \$4/MBTU onsite production) and 3 cent/kWh off-peak electricity

We have also estimated the cost of delivered hydrogen from our initial HGM-2000 product that produces 2,000 standard cubic feet of hydrogen per hour (scfh), enough to support approximately 160 FCVs, along with the estimated costs of hydrogen from a larger HGM-18,000 system that would support 1,440 FCVs. These hydrogen cost estimates are compared with the historical gasoline prices in Figure 7 in terms of the driver's fuel cost per mile, assuming that the FCV has 2.2 times higher fuel economy than the ICEV. The top three curves in Figure 7 compare the retail (taxed) price of gasoline with the range of prices for hydrogen made in the HFA-2000, depending on whether the local fueling

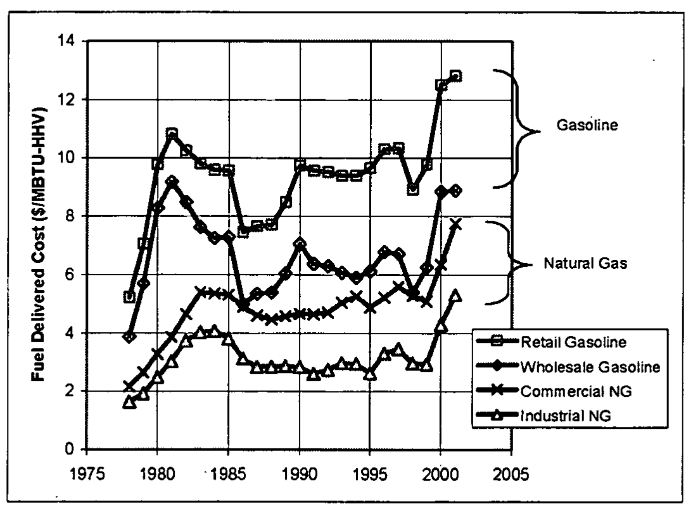
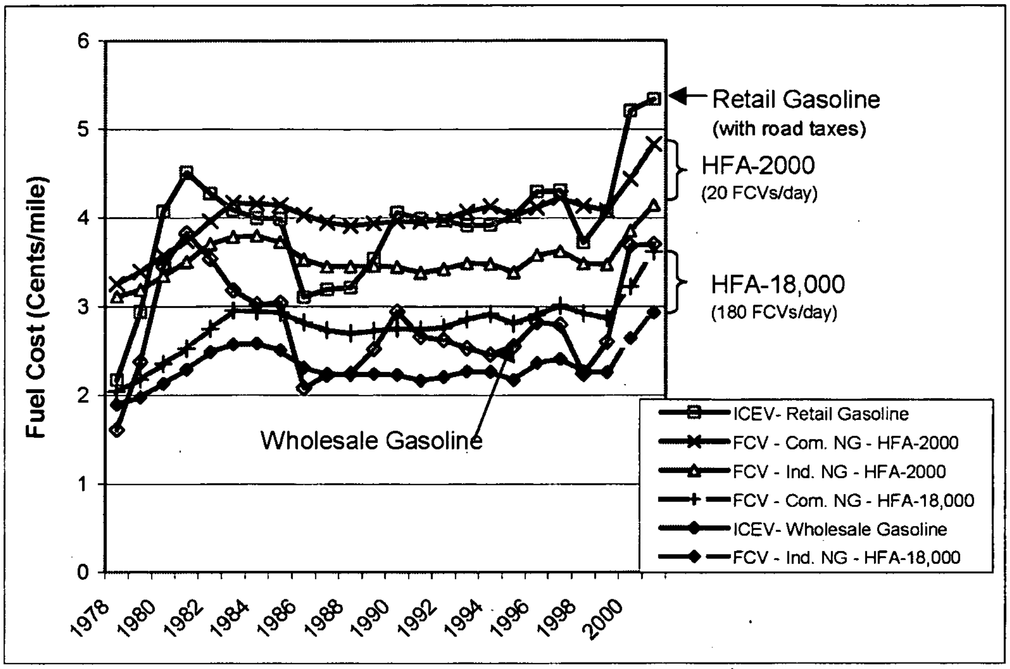


Figure 6. Historical US prices for delivered natural gas and gasoline in \$/MBTU

station or energy company can negotiate commercial or industrial natural gas prices. These curves illustrate that the FCV owner would pay about as much per mile for fuel as the driver of a conventional gasoline car.



FCV = Fuel Cell Vehicle; ICEV = Internal Combustion Engine Vehicle; HFA = Hydrogen Fueling Appliance
FCV fuel economy = 66 mpgge; ICEV fuel economy = 30 mpg; Capital Recovery Factor =0.184
Electricity = 6 cents/kWh; SMR efficiency (LHV/LHV) = 68.6%; 4-stage Compressor Isentropic Efficiency = 65%;
Output pressure = 7,000 psia; Input pressure = 235 psia; HFA Capacity Factor = 69%

H2Gen: NG-Price.XLS; Tab 'Gasoline-NG' T68- 2 / 19 / 2002

Figure7. Estimated cost of delivered hydrogen from two natural gas reformer systems compared to the historical costs of retail and wholesale gasoline

The bottom three curves in Figure 7 compare the costs of hydrogen from a larger fueling station supporting 1,440 FCVs (180 cars per day) with wholesale gasoline. With this larger HFA, we assume that hydrogen would have to be taxed. Again, these curves illustrate that over the last 22 years, hydrogen made from commercial or industrial natural gas onsite would be competitive with wholesale gasoline.

Another alternative to produce hydrogen onsite is to electrolyze water at the fueling system using grid electricity. The curves on the left side of Figure 3 (at 5 cents/kWh off-peak electricity) and Figure 5 (with 3 cents/kWh off-peak electricity) illustrate that such electrolytic hydrogen would cost less than hydrogen made locally from natural gas for very small fueling appliances serving less than 10 to 50 FCVs or one fuel cell bus. These charts assume, however, that off-peak electricity is available at 3 to 5 cents/kWh, which may be rare today. In any case, electrolyzers can be scaled to very small sizes sufficient for a few FCVs, whereas the natural gas reformers do not scale as readily to these small sizes economically.

4.3. Hydrogen Infrastructure Cost vs. Gasoline Infrastructure Cost

We have also analyzed and compared the cost of maintaining the current gasoline fuel supply system for conventional cars with the cost of a distributed hydrogen fueling system based on reforming natural gas at the fueling station. Each year the global oil industry invests many billions of dollars to maintain and upgrade the crude oil-to-gasoline fuel infrastructure system. Each year new wells must be dug and investments made in new technology to squeeze more oil out of existing wells. Oil companies must explore for new fields to keep the oil flowing. Investments are made in pipelines, oil tankers, refineries, gasoline tanks and pipelines, and local service stations. As summarized in Appendix C, we estimate that the oil industry must invest approximately $16.10/barrel of oil equivalent (BOE) produced in the US.

We next postulated how much the fuel industry would have to spend to build and maintain a distributed hydrogen fueling infrastructure based on reforming natural gas at the fueling station. The natural gas industry would have to increase its investments in maintaining the natural gas fueling infrastructure if FCVs increased natural gas consumption. The gas companies have to explore for new gas fields, invest in sinking new wells and maintaining and expanding natural gas processing plants and pipelines. In general processing natural gas (essentially removing contaminants and higher hydrocarbons) is less costly than refining crude oil to make gasoline. On the other hand, natural gas pipelines cost more than crude oil or gasoline pipelines or tankers per unit energy. From Appendix C, we estimate that the natural gas industry spends about $10.90/BOE[17] to keep the gas flowing (vs. $16.10/BOE for crude oil to gasoline.) This is equivalent to $1.86/MBTU of natural gas produced.

The total oil industry investments to maintain the global crude oil/gasoline fueling system amount to approximately $2,146 for each new ICEV sold, assuming 25 mpg average light duty vehicle fuel economy, 13,000 miles traveled per year, and a 12-year life-time. We estimate the cost of maintaining and expanding the natural gas fuel supply system plus the cost of installing small scale hydrogen fueling appliances based on reforming natural gas at the fueling station would be only $1,542 for each new FCV sold. This sum includes $1,009/FCV to maintain and expand the natural gas infrastructure, and $533/FCV to install the hydrogen fueling appliances. This results in a net savings in fuel infrastructure costs of $604 for each new FCV sold in place of an ICEV.

As shown in Appendix C, this savings could increase to $55 to $74 billion each year in fuel infrastructure savings by 2040, assuming the FCV market penetration scenarios postulated in Appendix B. Cumulative savings could amount to $840 billion to $1.1 trillion over the next 40 years.

4.4. Hydrogen Impact on Natural Gas Resources

Generating hydrogen from natural gas could conceivably put a major strain on global natural gas resources if tens of millions of direct hydrogen FCVs were sold around the world each year. A key question is whether there are enough natural gas reserves to support a serious FCV fleet around the world until such time as renewable hydrogen is cost competitive. In Appendix B we analyzed two hypothetical FCV market penetration scenarios and estimated the impact on natural gas resources over the next 40 years. In the first scenario, we postulated that carmakers would sell 40,000 direct hydrogen FCVs by 2010, all running on hydrogen from natural gas, with sales rising to 60% of

[17] 1,000 standard cubic feet (SCF) of natural gas is equivalent to approximately 0.178 BOE or 1.041 MBTU (HHV).

world total new car sales by 2030 and thereafter. In the second, more optimistic scenario, we calculated the impact of selling 40,000 FCVs by 2007, rising to 80% of all sales by 2030.

Based on this assessment (see Appendix B), we conclude that generating all hydrogen from natural gas would reduce oil consumption by 700 to 1,000 quads (cumulative) by 2040 as hydrogen-powered FCVs replaced gasoline-powered ICEVs. Natural gas consumption would increase by 500 to 700 quads, or a net reduction in fossil fuel consumption of between 200 and 300 quads. Over this 40-year period, the total estimated natural gas resources[18] would be decreased by only 8% to 11% compared to business as usual with no FCV sales, which corresponds to only a two-year acceleration of natural gas depletion.

In addition to a net reduction in fossil fuel consumption of between 200 to 300 quads, shifting to hydrogen-powered FCVs would also tend to improve the growing global imbalance between crude oil and natural gas reserves. Total natural gas resources currently exceed estimates of current crude oil reserves by a very small margin. Furthermore, the world is consuming crude oil faster than natural gas. If these trends continue, recoverable crude oil will become scarce more quickly than natural gas over the next four decades. Direct hydrogen FCVs would help to correct this imbalance by shifting consumption from crude oil to natural gas.

We conclude that the use of natural gas to supply hydrogen for FCVs should not place a major burden on world natural gas resources, on the average. However, regional variations may mean increased cost for natural gas in the future. For example, if North American natural gas resources were strained, and if LNG were required to be imported from the Caribbean or the Middle East, then natural gas prices would increase, making hydrogen from natural gas less competitive than calculated here. We did not analyze these regional variations.

4.5. Hydrogen Safety

Hydrogen, like any fuel, presents certain risks due to its high energy content. Hydrogen, in many respects, is similar to natural gas, a fuel that is piped into most American homes and fuels more than 700,000 natural gas vehicles around the world. Both gases are lighter than air and will therefore rise when released, unlike gasoline or propane fumes that are heavier than air and will linger in the vicinity of any accidental release. Thus hydrogen, like natural gas, is considered safer than gasoline or propane in an open environment.

But natural gas and hydrogen do pose a threat in closed spaces such as a home garage. Each year an average of 4,100 Americans die from home fires. But only 57 of these fatalities or 1.4% are caused by leaking natural gas that ignites from electrical sparks or even static electricity. For comparison, smoking is responsible for 25% of all home fire fatalities – smoking is 17 times more dangerous than natural gas in terms of home fire deaths[19]. Although natural gas is dangerous, we have all come to accept the inherent risks of piping natural gas into our homes in exchange for the convenience it brings.

Before World War II, many American homes were also heated by "town gas," which was produced by gasifying coal. Town gas, also known as "coal gas", which still is used in Hong Kong and

[18] Natural gas resources includes proven reserves, reserve margin, and undiscovered but recoverable resources.
[19] John R. Hall, Jr., *The U.S. Fire Problem Overview Report through 1993: Leading Causes and other Patterns and Trends in Home,* the National Fire Protection Association, Quincy, Massachusetts, January 1995, p. 68.

elsewhere, is composed of over 50% hydrogen with the remainder carbon monoxide, methane, and carbon dioxide. Town gas was used extensively in Great Britain beginning in the early 19th century, with some 48 km of cast iron gas pipes laid in London by 1815[20]. Incredibly, wooden pipes were used in the US as late as 1870 to carry hydrogen-rich town gas to American shops and homes. Again, we accepted having hydrogen gas in our homes despite the risk (although many people may not have known they were burning hydrogen to heat their homes and light their lamps.)

Except for the use of town gas in homes prior to World War II, we have little modern statistical data to rate the likely risk of hydrogen compared to gasoline. However, we do have a surrogate comparison. Hydrogen is similar to natural gas, while gasoline is similar to propane, in that both propane and gasoline fumes are heavier than air, and both gasoline and propane have very low flammability limits in air (propane will burn at concentrations of 2.1%, gasoline at 1.0%, whereas natural gas and hydrogen require at least 4% concentration before a fire can start.) Approximately 5 million homes are heated by propane and 47 million by natural gas. The risk of dying in a propane-instigated fire is about 6.8 out of a million in a propane-heated home, compared to 1.6 per million homes for natural gas. Thus a homeowner is four times more likely to die from propane than natural gas. To the degree that hydrogen is more similar to natural gas than to gasoline and propane, then, one could infer that hydrogen would be less dangerous in a home garage than gasoline[21].

To mitigate the risk of a natural gas fire, odorants such as mercaptans are added to warn the homeowner of any leaks before an explosion. Mercaptan, which contains sulfur, cannot be added to hydrogen intended for fuel cells, however, since the fuel cell is poisoned by sulfur. Instead, hydrogen sensors may be added to home garages to warn the owner of any leaks. In one sense these sensors are superior to adding odorants, since they can detect any hydrogen leak and provide warning *before* someone enters the garage.

The perception that hydrogen is a dangerous fuel lingers in some people's minds due to the Hindenburg fire that destroyed the transoceanic dirigible at Lakehurst, New Jersey on May 6, 1937 as it docked, killing 35 of the 97 passengers and one person on the ground. Hydrogen was used to give the Hindenburg buoyancy in place of helium that was embargoed during the war. Over the years people have associated the Hindenburg fire with hydrogen, thanks in part to a live radio broadcast of the disaster and newsreel films. But Addison Bain, an ex-NASA official, has analyzed the outer cloth bags that held the hydrogen on the Hindenburg[22]. He found that the cloth had been coated with iron oxide and several layers of cellulose butyrate acetate, a highly flammable material. Aluminum powder was also added to reflect sunlight. But metal powder in cellulose acetate is also a potent rocket fuel, similar to those used in the Shuttle solid booster rockets. Bain concludes that the most probable cause of the Hindenburg fire was static electricity (the dirigible approached Lakehurst with electrical storms in the vicinity, violating company regulations) igniting the flammable outer cloth.

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[20] Trevor I. Williams, "A History of the British Gas Industry," Oxford Press, 1981, p. 15.

[21] C. E. Thomas, *Direct Hydrogen-Fueled Proton Exchange Membrane Fuel Cell System for Transportation Applications: Hydrogen Vehicle Safety Report*, prepared by Directed Technologies Inc. and the Ford Motor Company for the U.S. Department of Energy under Contract No. DE-AC02-94CE50389, May 1997.

[22] Addison Bain and Wm. D. Van Vorst, "The Hindenburg tragedy revisited: the fatal flaw found," *Int. J. of Hydrogen Energy*, 24 (1999) pg. 399-403.

Hydrogen has also been falsely tarnished in some people's minds by association with the hydrogen bomb. In fact the "hydrogen bomb" would not work with hydrogen. A hydrogen bomb or thermonuclear device actually requires the fusion of deuterium and tritium, the isotopes of hydrogen. In addition, an atomic bomb or fission trigger is required to set off a thermonuclear device. So there is absolutely zero possibility that hydrogen gas could create an explosion analogous to a "hydrogen bomb."

In summary, hydrogen does pose risks that are different from but not necessarily worse than other fuels, in the aggregate. Hydrogen is considered safer than gasoline in an outdoors accident. Carbon fiber-wrapped composite hydrogen tanks are far more durable than plastic gasoline tanks, and would most likely survive all but the most horrific crashes intact. Indoors, hydrogen gas will accumulate at the ceiling of an airtight garage, while gasoline or propane fumes will accumulate near the floor. Thus hot water heater flames must be kept off the floor of a garage with a conventional car, and ignition sources must be avoided near the ceilings for a hydrogen-powered vehicle.

5. Transition Strategy for Hydrogen and Fuel Cells

Many proponents of hydrogen and fuel cells have a clear vision of the end game: hydrogen and electricity produced by renewable energy sources, with hydrogen supplying the transportation sector and acting as a storage medium for intermittent renewables like wind and PV. The challenge is getting from here to there. The energy industry will not invest hundreds of millions of dollars to put in a hydrogen infrastructure overnight when there are only a handful of FCVs on the road. Similarly, the carmakers will not spend billions to make fuel cell vehicles when there is no hydrogen infrastructure. And neither industry is likely to make the necessary investments solely to achieve societal objectives of reduced dependence on imported oil and cleaner air. Government support will be required to jump-start the hydrogen/fuel cell future on behalf of all citizens, with the understanding that hydrogen and fuel cells must eventually be economic without any government subsidy.

We offer the following strategy to move gradually toward the goal of a sustainable energy future based on renewable hydrogen, using the existing natural gas infrastructure to make hydrogen at the local fueling station as the bridge fuel to form an economic pathway until such time as renewables are cost effective. We suggest five steps:

1. <u>Distributed Power Generation.</u> Install stationary PEM fuel cells powered by natural gas as part of a distributed electrical generation system.
2. <u>Hydrogen Cogeneration.</u> Cogenerate hydrogen from the fuel processors of these stationary fuel cell systems to supply industry and the evolving FCV fleet of buses and cars.
3. <u>Small-scale Onsite Electrolyzers</u>. Install a *limited* number of small-scale electrolyzers to provide hydrogen for early FCV fleets with less than ten passenger vehicles or two fuel cell buses.
4. <u>Small-scale Onsite Natural Gas Reformers</u>. As FCVs proliferate, add small-scale reformers to produce hydrogen onsite from natural gas at the fueling station.
5. <u>Renewable Hydrogen</u>. As renewable energy sources become economic in any region, supplement hydrogen from natural gas with renewable hydrogen.

The rationale for each phase is discussed below. While listed as discrete steps, in fact all five phases may overlap and coexist in time and geography depending on local conditions.

5.1. Phase 1 – Distributed Fuel Cell Power Generators

Stationary fuel cell systems for distributed generation of electrical power will be cost competitive before fuel cells for transportation. Natural gas ICE generators in the 100 kW to 1MW range cost between \$400/kW and \$500/kW, while the venerable internal combustion engine for vehicles can be mass produced at costs of less than \$15/kW. While the stationary fuel cell should be an order of magnitude more durable (say 50,000 hours life vs. 4,000 for a vehicle fuel cell) and hence more costly to manufacture, the price premium paid for power generation still favors stationary applications before mobile applications.

The successful development and marketing of stationary PEM fuel cell systems will assist the development of mobile fuel cell systems. The stationary fuel cell system includes both the fuel cell itself plus the fuel processor to convert natural gas (or propane) to hydrogen. These stationary fuel processors can also be used to generate hydrogen for FCVs[23]. Mass production of stationary fuel cell systems should therefore help to drive down the costs of both fuel cells and fuel processors[24]. The government should therefore assist the fuel cell industry to develop and install stationary PEM fuel cell systems.

5.2. Phase 2 – Hydrogen Cogeneration from Fuel Cell Power Generators

Stationary fuel cell systems will generally be underutilized at night, when electricity demand is typically low. To improve economics of a project, the stationary fuel processor could be utilized at night during off-peak hours to generate and store hydrogen for later use. A hydrogen compressor and storage tanks would have to be added, but our analyses have shown that producing both hydrogen and electricity can significantly improve the economics of a system selling only one product.

For example, Figure 8 shows the tradeoff between electricity price and hydrogen price for such a cogeneration system. The PEM fuel cell produces 50 kW of AC power for a building or factory. The natural gas reformer is oversized to produce enough hydrogen for 200 FCVs or 4 or 5 fuel cell buses, assuming a 50% electrical capacity factor. Under these conditions, the owner of the 50-kW fuel cell system would earn a 10% real, after-tax return on investment if the electricity were sold at 16 cents/kWh if 100 such systems were produced and no excess hydrogen was produced for sale. But with hydrogen cogeneration, the owner could reduce the cost of electricity along the sloped line of Figure 8 and still make his 10% return on investment. For example, if the owner could sell hydrogen to support 200 FCVs or 4 fuel cell buses at a price of \$1.30/gallon of gasoline equivalent, then the electricity price to the building owner could be reduced to only 4 cents/kWh. These values assume that 100 fuel cell systems are produced. If 10,000 such systems were manufactured, then the costs could be reduced according to the lower two lines. Without hydrogen sales, an electricity price of 11.3 cents/kWh would be required for a 10% return. With hydrogen sales, then electricity

[23] Most early stationary fuel cell companies used impure hydrogen contained in the reformate from their fuel processors; the H_2Gen hydrogen generation module (HGM) produces pure hydrogen that would be suitable for refueling vehicles.

[24] However, the stationary fuel cell systems will probably never reach the mass production levels of the automobile industry. We would expect at most 10,000 to 20,000 stationary fuel cell systems per year, compared to 300,000 or more for a robust automobile production line.

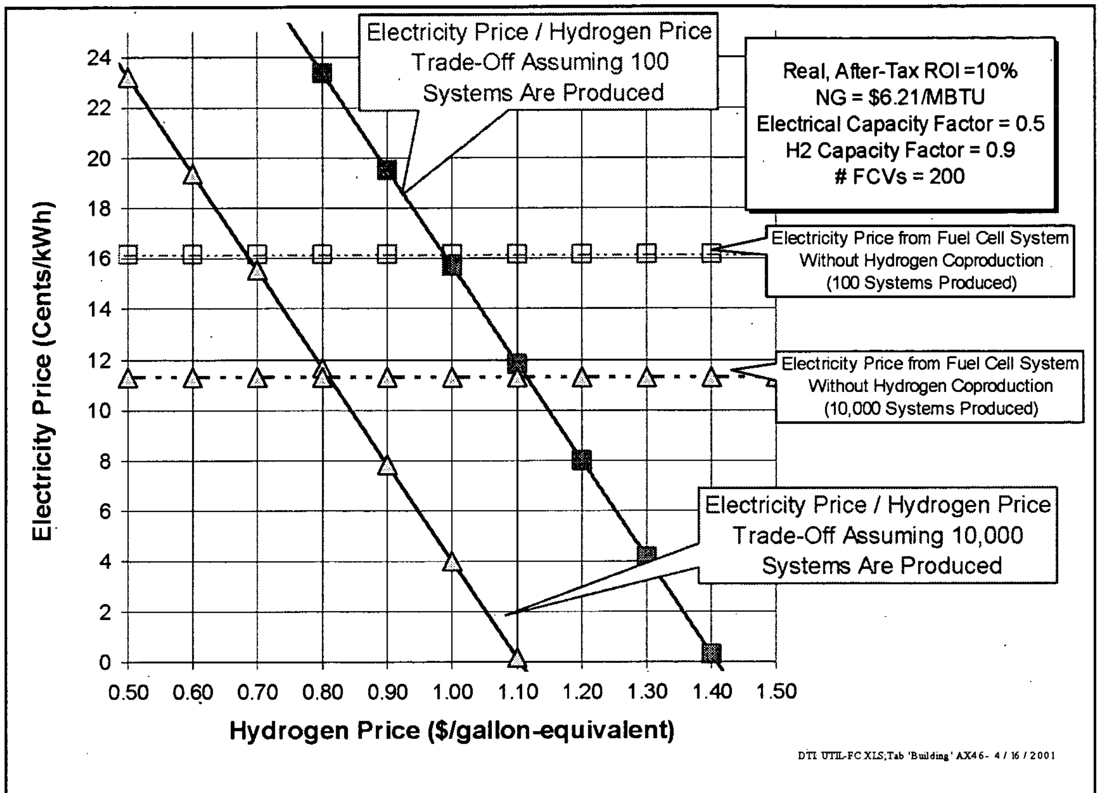

Figure 8. Illustration of trade-off between hydrogen price and electricity price for a 50-kW stationary fuel cell system co-producing hydrogen.

could be sold at 4 cents/kWh as long as hydrogen was sold at $1/gallon of gasoline equivalent. Of course in this example, the fuel cell system owner would most likely be able to increase his prices for both commodities and earn more than 10% return.

The capital costs in this model were estimated at $1,670/kW at the 100-unit production level for the fuel cell system alone, falling to $776/kW at the 10,000-production level. At this level, the fuel cell system component costs are estimated at $270/kW for the steam methane reformer system, $326/kW for the fuel cell stack and ancillary components, and $180/kW for the inverter/controller system. Adding the oversize reformer increased total costs to $2,500/kW at the 100-unit production level, and to $1,100/kW assuming 10,000 units were built.

While Figure 8 is based on selling the off-peak hydrogen to FCV owners, the hydrogen could also be sold to local industries that need hydrogen for the production lines, including the foods industry (hydrogenation), metals, float glass, utility generator cooling, etc. The ideal customer might need assured electrical power plus a supply of low-cost hydrogen. This system modeled in Figure 8 could produce 100 kg or 42,300 standard cubic feet of hydrogen per day for industrial uses.

Figure 8 assumes that a stationary fuel cell system is installed for the primary purpose of selling electricity, and hydrogen is added as a co-product. We have also analyzed the reverse situation: the owner installs a hydrogen fueling appliance to supply fuel cell buses or cars. The owner then adds a

stationary fuel cell system to provide electricity for peak shaving during the afternoon hours only. The economics of this cogeneration system are illustrated in Figure 9. In this case the hydrogen fueling appliance is scaled to support 300 FCVs or 5 to 6 fuel cell buses. A 75-kW stationary fuel cell is added to produce electricity during six hours of on-peak time for the utility grid, when the electricity can be sold at a premium price. This fuel cell effectively runs on hydrogen made at night, when FCV fuel sales are low. In this manner the capacity factor of the fuel processor is increased. Run just six hours per day, this fuel cell system could earn the target 10% real, after-tax return on investment by selling electricity at 15 cents/kWh during the peak hours only.

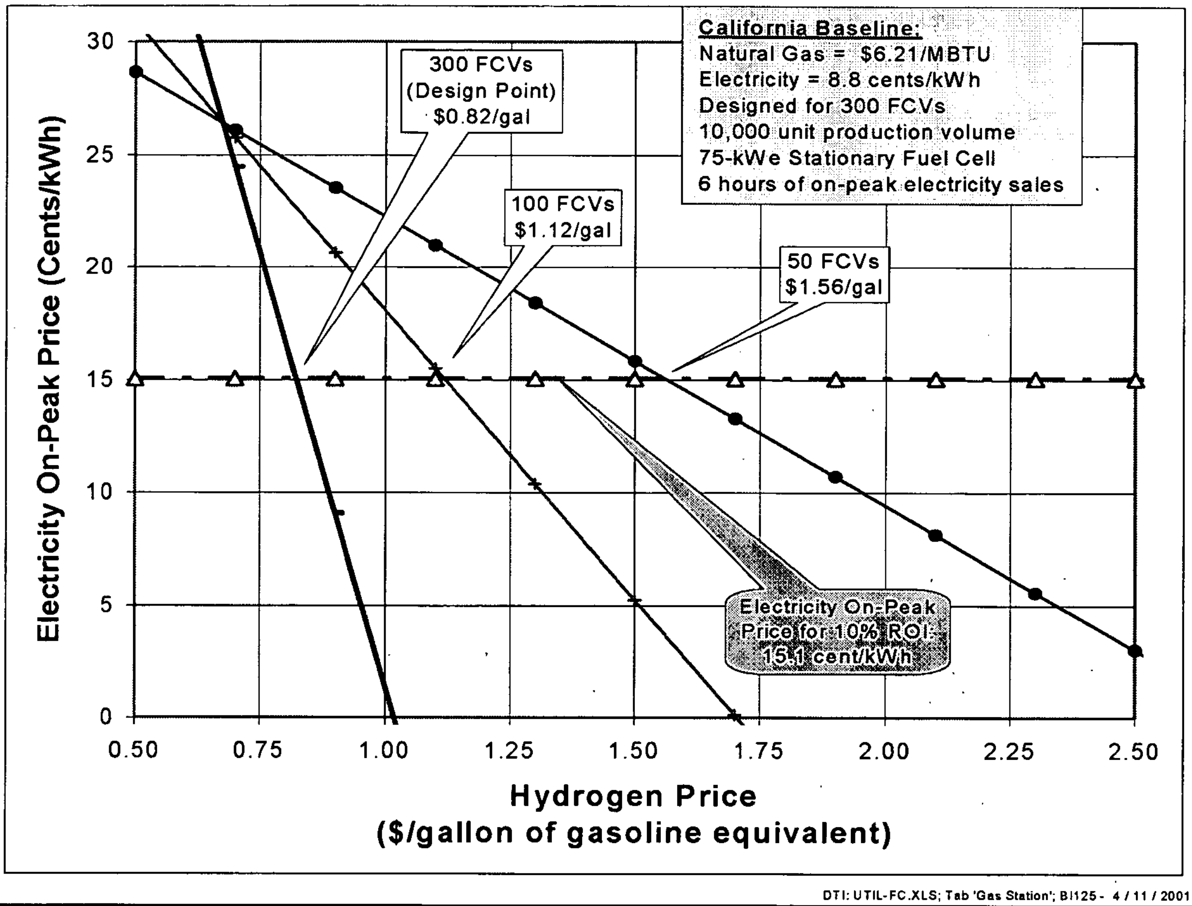

Figure 9. Illustration of price trade-off between on-peak electricity and hydrogen for a hydrogen fueling station with an auxiliary fuel cell for peak shaving only

The slanted lines in Figure 9 illustrate the price tradeoffs for different quantities of FCVs supported by the fueling station. For example, the right-most curve assumes that only 50 FCVs (or one fuel cell bus) are available initially. Without electricity co-generation, the hydrogen would have to be sold at $1.56/gallon of gasoline equivalent (excluding taxes). In this case the owner of the facility might choose to move up the line, increasing the price of the on-peak electricity to 20 cents/kWh while reducing the price of hydrogen to $1.20/gallon of gasoline equivalent. When 100 FCVs (or two buses) were fueled at the station, then the owner could charge $1.20/gallon for the hydrogen and sell the electricity at 13 cents/kWh. Again, the owner would probably charge more for the on-

peak electricity, and increase his profit margin. Once 300 FCVs used this fueling station, the owner could make the target 10% return on investment as long as the hydrogen were sold at more than $1/gallon of gasoline equivalent and the on-peak electricity was sold for more than 5 cents/kWh.

5.3. Phase 3 – Small-Scale Onsite Electrolyzers

Initial passenger vehicle FCVs will undoubtedly be sold to fleet operators that have central refueling. These fleet owners will initially purchase at best a few FCVs on a trial basis. As shown by Figure 3 above, small-scale natural gas reformers are not cost effective for less than 10 to 50 FCVs or one fuel cell bus. We propose the use of small-scale electrolyzers for these early applications, even though hydrogen will cost more than gasoline per mile driven and these electrolyzer systems will dramatically increase greenhouse gas emissions as discussed in Section 3.2 above. We would not recommend electrolyzers for fuel cell bus applications, however, since one bus will consume the same hydrogen as 30 to 40 FCVs. Again referring to Figure 3, a small-scale steam methane reformer serving one bus (30 to 40 FCVs on the figure) would be cost competitive with electrolytic hydrogen but with a net 40 to 50% decrease in greenhouse gas emissions instead of a substantial increase.

Electrolyzers are a bit of a dilemma for this scenario. We see a need for electrolyzers as an economic source of hydrogen in the very early days when there are too few passenger FCVs to support steam methane reformers. But electrolyzers are not acceptable from a climate change perspective in the mid-term as long as the US power grid depends primarily on coal power. The EIA projects very little decrease in the use of coal for power generation, estimating that the fraction of coal used to produce electricity will decrease from 54.9% today to a still hefty 48.6% by 2020[25]. Eventually, as some combination of renewables and nuclear power began to dominate the electrical grid, then electrolyzers would be needed once again to produce the hydrogen needed for transportation systems. Thus the electrolyzer industry is faced with a two to four decade gap between the initial, relatively modest need in the transportation market and the final, much larger requirement for electrolyzers in a renewable hydrogen economy.

5.4. Phase 4 – Small-Scale Onsite Natural Gas Reformers

Once a given fleet owner accumulated more than 10 FCVs or one or two fuel cell buses, he could in principle sell back his electrolyzer and purchase a small-scale steam methane reformer. Or the owner could lease the electrolyzer initially. In either case, the electrolyzer could then be transferred to another fleet owner just starting down the FCV path. In this manner the fleet owner would reduce his fuel costs while the societal impact of added greenhouse gases from electrolyzers could be reduced.

Ideally these fleet operator hydrogen fueling appliances could be open to the public, so that the fleet sites would contribute to initial public access[26]. These small-scale hydrogen fueling appliances could be placed at existing gasoline stations as illustrated by the two small boxes labeled HGM (hydrogen generation module) and HCM/HSM (hydrogen compression module/hydrogen storage module) in Figure 10 for a small corner gas station, still leaving room for gasoline tanker trucks to fill the gasoline underground tanks (assuming just one hydrogen dispenser initially, with the other three islands dispensing gasoline). Government support would probably be needed initially to begin

[25] Energy Information Administration, *Annual Energy Outlook 2002*, Table A8, AEO2002 Reference Case Forecast.

[26] Sunline Transit in Palm Desert, California east of Los Angeles has set this precedent; their hydrogen fueling station for fuel cell buses is open to the public.

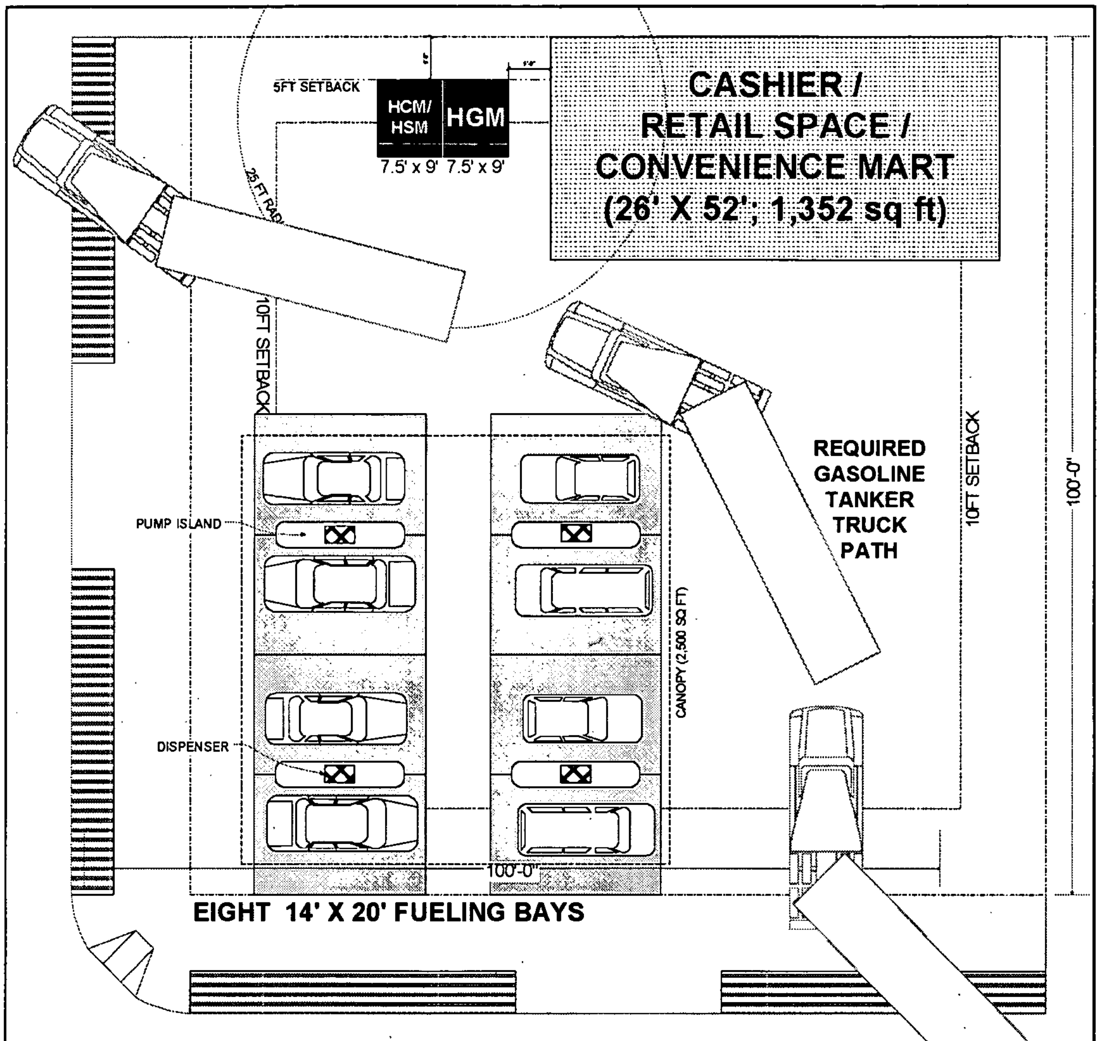

Figure 10. Illustration of a small-scale hydrogen generation module (HGM) coupled with a hydrogen compression module (HCM) and a hydrogen storage module (HSM) at a small corner gas station

installing hydrogen fueling appliances at conventional fueling stations. This approach was taken by the State of California in an attempt to promote methanol-powered ICEVs in the 1980's. The state paid for the methanol tanks and pumps, and the oil companies agreed to pay for installation[27].

We estimate that these small-scale hydrogen fueling appliances[28] based on steam methane reforming could be mass produced at a cost in the range of \$150,000 to \$200,000 each. Based on the experience of diesel fuel where conversion of 10% of the stations was considered as a lower

[27] Unfortunately this attempt at promoting an alternative fuel was defeated since owners of the flex-fuel vehicles that could run on gasoline or methanol opted to use gasoline most of the time. The car companies reaped the rewards of CAFÉ credits, but the intended reduction in pollution and oil dependence did not materialize. Most of these methanol fueling sites have now been closed.

[28] The initial H_2Gen hydrogen fueling appliances will support 160 FCVs. As FCV customers at each fueling station exceed 160, then more modular fueling appliances would be added.

threshold for driver acceptance, the hydrogen industry would have to add approximately 1,000 fueling appliances in California. Total cost is then estimated between $150 million to $200 million to begin a modest but effective hydrogen fueling infrastructure in California. The cost for 10% fueling station coverage in the entire US would be on the order of $2 billion, far less than the $100 billion plus estimates of some analysts based on installing a national hydrogen pipeline system.

5.5. Phase 5 – Renewable Hydrogen

Eventually most hydrogen would be generated by some type of renewable energy. Intermittent renewables such as wind and PV would feed electrolyzers to make hydrogen when the renewable energy exceeded the grid load. Hydrogen would also be produced by gasifying biomass, landfill gas, coal bed methane and municipal solid waste.

A key attribute of this five-phase transition is its flexibility. In particular, renewable hydrogen can be added gradually over time and space. Initially, wind energy would most likely produce hydrogen economically in the upper Midwest, once electrical grid transmission capacity was exceeded on windy days. PV hydrogen would come much later in the Southwest once the cost of solar cells is driven down through large-scale mass production. Switchgrass grown as a dedicated energy crop in the Southeast might be a good candidate for producing hydrogen by gasification. The transition to the last phase would be market-driven in each region of the country and the world. As natural gas prices rise over the next few decades and renewable energy prices fall, companies will switch from natural gas reformers to renewable energy sources. This gradual transition to a renewable hydrogen economy would be strictly market-driven. All government subsidies used to jump-start the hydrogen and fuel cell transition would be terminated long before renewables entered the marketplace. Our economic evaluations indicate that hydrogen produced from natural gas would be economic without any government support in a mature market.

6. Alternative Transition Strategies

The costs and benefits of this hydrogen and fuel cell transition strategy should be compared with other alternatives to improve our energy security and our environment.

6.1. Other Transportation Alternatives

6.1.1. Hybrid Electric Vehicles

Our dependence on imported oil could be reduced to some degree by introducing new ICE-based technologies such as hybrid electric vehicles (HEVs). The Toyota Prius and the Honda Insight are HEVs that are now sold commercially. These HEVs and others soon to be introduced by carmakers will improve fuel economy by 50 to 100% compared to current technology. These HEVs rely on a small onboard internal combustion engine that is connected to the road through a special transmission or coupled to a generator to charge the car's batteries, depending on the vehicle operating mode. The battery and electric motor provide an acceleration boost when needed, allowing the use of a smaller ICE. Since the HEV ICE is smaller and is run closer to its "sweet spot" of high efficiency much of the time, overall fuel economy is improved compared to conventional ICEVs where the engine must operate over the full range of torque and RPM where efficiency suffers. However, this improved fuel economy for individual new cars will be offset over time by the increase in total vehicle miles traveled by all cars and trucks. As mentioned previously, the EIA estimates that VMT will increase 57% by 2020. Thus a 50% increase in fleet fuel economy would not even maintain the status quo on oil imports – a great improvement over current

projections of negligible net improvement in fleet average fuel economy, but far short of what could be accomplished by introducing FCVs running on hydrogen derived from natural gas. Thus HEVs are not a long-term option to achieve a sustainable energy future. They will merely prolong and stretch out our dependence on imported oil.

6.1.2. Gasoline-Powered Fuel Cell Vehicles

Another alternative is to use gasoline as the FCV fuel by adding an onboard reformer to convert the gasoline to hydrogen. The DOE continues to fund research and development to produce a viable onboard gasoline reformer, but the technical and economic challenges are daunting[29]. The fuel cell vehicle has the potential to more than double the fuel economy of current cars. But the onboard reformer system to convert gasoline to hydrogen would likely have less than 65% net efficiency, taking into account all parasitic loads and startup energy required to operate a very complex chemical processing system. The added weight of this onboard reformer and fuel cell system would also degrade vehicle fuel economy. As a result, the fuel economy of a gasoline-powered fuel cell vehicle would most likely be much less than the potential two times improvement of a pure hydrogen fuel cell vehicle. In any case, like the HEV, a gasoline FCV would still require imported oil to sustain the transportation system, albeit less than with current gasoline ICE vehicles. It is not clear to us that the gasoline FCV has any societal advantage over the ICE hybrid EV in terms of national security or environmental impact. Since the ICE HEV is commercially available today at a modest increase in cost (currently subsidized by the auto companies), and since the gasoline FCV has yet to be developed let alone produced commercially at a reasonable cost, the HEV appears to be a better interim option than a gasoline FCV.

Still, if the DOE and its contractors succeed in developing an affordable and reliable onboard reformer, then FCVs could be put on the road without significant fuel infrastructure investments[30]. This could allow the scale up in fuel cell stack manufacturing volume sooner than for a direct hydrogen FCV, driving down their costs. On the other hand, if gasoline FCVs should enter the marketplace in volume, one could argue that this would *postpone* the transition to a sustainable hydrogen future—if gasoline FCVs were perceived to be a positive step in reducing pollution and dependence on oil, it might be more difficult to make the switch to direct hydrogen FCVs. In any case, the main rationale for developing gasoline FCVs is the notion that installing a hydrogen infrastructure would be prohibitively expensive. As discussed above, we do not believe this is the case, given our recommendation of utilizing small-scale steam methane reformers at the fueling station. In our judgment, direct hydrogen FCVs combined with onsite hydrogen fueling appliances could be achieved sooner than gasoline FCVs and at lower total cost.

6.2. Other Distributed Power Grid Alternatives

The primary competitors to stationary PEM fuel cells in the 100 kW to 1 MW range for distributed power generation will be diesel generators, natural gas reciprocating engine generators and

[29] C. E. Thomas, B. D. James, F. D. Lomax, Jr., and I. F. Kuhn, Jr., "Fuel options for the fuel cell vehicle: hydrogen, methanol or gasoline?," *Int. J. of Hydrogen Energy*, 25 (2000) pp 551-567.

[30] This assumes that gasoline FCVs use conventional pump-grade gasoline. It may be necessary, however, for the oil companies to produce a fuel cell grade of gasoline with essentially zero sulfur content and possibly without some other onerous gasoline additives used to enhance ICE performance. If the FCV requires a new grade of gasoline, then there will new infrastructure investments required, and FCV owners will not be able to refuel at all gasoline stations, but only those that have added the fuel cell grade of gasoline.

microturbines running on natural gas[31]. Diesel generators are acceptable for standby and emergency power, but probably will not be used for continuous distributed power due to a combination of low efficiency, noise, and emissions of NOx and particulates. In addition, increased use of diesel fuel for electrical generation would increase, not decrease, our dependence on imported oil[32]. On the other hand, microturbines and ICE gensets running on natural gas will be strong competitors. The PEM fuel cell has the potential for lower noise, less emissions, less maintenance and possibly higher efficiency than either microturbines or reciprocating engine generators running on natural gas.

The key challenge will be to drive costs for the full fuel cell system (including reformer and the inverter/controller) down to the $750/kW range to be economically competitive. In principle the fuel cell system can cost somewhat more if it operates at higher efficiency than the competition. Current microturbines have efficiencies near 26%, while natural gas ICE gensets have system efficiencies in the range of 34% to 36% for 100 kW to 500 kW systems. The PEM fuel cell may achieve 65% cell efficiency operating at low current density[33] (to extend lifetime), but the total system efficiency must include the losses in the reformer, the inverter/controller, and the stack ancillary systems. Assuming 70% LHV natural gas reformer efficiency, 10% parasitic losses for stack ancillaries and 95% inverter/controller efficiency, then the net PEM fuel cell system efficiency would be 39% (AC electricity out divided by LHV of natural gas in). Thus the PEM fuel cell system should have a significant efficiency advantage over microturbines (39% vs 26% now with claims for 30% for future microturbines), but only a marginal improvement (3 to 4 percentage points) over natural gas reciprocating gensets at 34% to 36%. The PEM fuel cell system will therefore have to be sold primarily on the basis of lower noise, lower maintenance and lower local emissions to compete with reciprocating engine generators running on natural gas.

7. Government Incentives

7.1. Financial Incentives

Although the auto industry is investing several hundred million dollars in FCV research, neither they nor the oil industry are likely to invest the several billions of dollars needed to bring hydrogen and fuel cell vehicles to the marketplace. Car companies are developing a few tens or at best hundreds of FCVs, but these are prototype development vehicles, not pre-production models. They have no bottom-line incentive to commercialize FCVs that will cost more to produce while having at best equal performance to current cars from the customer perspective. Some buyers will pay a premium for super clean FCVs, but the automakers do not perceive enough demand for clean vehicles to begin serious production lines.

The energy industries are investing much less in hydrogen infrastructure developments. Shell Oil has formed a hydrogen division, but it is staffed at fewer than 30 people. They have invested in a joint venture with UTC Fuel Cells (formerly International Fuel Cells) called HydrogenSource to develop fuel processors, both stationary and onboard. Texaco has demonstrated an interest in hydrogen and fuel cells, and has invested in Energy Conversion Devices of Troy, Michigan to

[31] Solid oxide and molten carbonate fuel cells with combined cycle turbines may also be competitive at power levels above 1 MW, but probably not in the 100 kW to 500 kW range for small distributed power sources.
[32] Currently only 2.7% of all US electricity is generated from fuel oil.
[33] This assumes operating at a cell voltage of 0.8 volts, well below the peak power point for a PEM fuel cell near 0.6 volts. Thus the fuel cell stack would have to be much larger, increasing capital costs. The optimum operating point will depend on the cost of natural gas and the lifetime and maintenance costs associated with higher current density.

jointly develop hydride storage systems, nickel metal hydride batteries and reversible fuel cells. But the oil companies have very little incentive to set up hydrogen fueling stations with little prospects of FCVs for many years.

In short, the primary advantages of hydrogen-powered fuel cell vehicles are societal benefits including cleaner air and less dependence on imported oil. These advantages accrue to society as a whole, and government should help to pay to introduce these technologies into the marketplace. Government financial incentives should stimulate both the fuel cell industry and the distributed hydrogen energy. Both are essential.

On the fuel cell side, we would recommend tax-neutral feebates for automobiles: the government would charge a fee similar to the existing "gas-guzzler" tax on all sales of conventional ICEVs, inversely proportional to their fuel economy. The revenues from these gas-guzzler taxes would be rebated to purchasers of FCVs with some funds possibly used for FCV or hydrogen infrastructure R&D.

Similarly, on the hydrogen infrastructure side, we propose tax-neutral fuel feebates. Gasoline taxes would be increased modestly to generate a fund to help finance hydrogen infrastructure developments and deployments, and to pay down the initial increased cost of hydrogen with a low number of FCVs on the road. For example, a 1 cent/gallon increase in gasoline taxes would raise approximately $1.3 billion per year. This would be enough to purchase and install 6,500 hydrogen fueling appliances each year, or enough to place one hydrogen fueling appliance at 65% of all California fueling stations the first year of the program. In effect, this modest increase in gasoline taxes would be a baby step toward accounting for the real societal impact of burning gasoline in ICEVs. The 1.0 cent/gallon tax increase is dwarfed by the gasoline taxes in other industrialized nations, which often exceed several dollars per gallon[34]. And yet this minor increase would help to launch an effective hydrogen infrastructure system.

7.2. Regulatory Incentives

The lack of codes and standards for hydrogen at local fueling stations could be a major obstacle to widespread introduction of a hydrogen infrastructure based on compressed hydrogen. The Federal government is not directly involved with the standards development process. Standards are generally written by industry groups such as the National Fire Protection Association. (NFPA), the Society of Automotive Engineers (SAE), the ASME, ASHRE, etc.. Writing new standards can take many years, requiring lengthy committee actions and revisions. DOE representatives have participated in some of these activities, but often have not had the experience or capability to affect necessary modifications to draft codes and standards. Ideally the government should strive to influence the process by helping to publicize the benefits of and urgent need for alternative fueling systems such as hydrogen. The DOE National Labs have been assisting the process by conducting safety tests on components such a compressed gas tanks. This support should continue as needed.

[34] The author is quite aware of the political difficulties of increasing highway taxes of any magnitude. Strong political leadership would be required, along with a convincing discussion of the societal merits and a program that would assure that the gasoline tax revenues would only be used to improve transportation options and would not end up in the general fund.

7.3. Education

The DOE should continue and expand its activities in publicizing the national security and environmental benefits of hydrogen and fuel cells. Future customers need to learn about and be comfortable with new technologies such as hydrogen and fuel cells. The DOE has previously sponsored several projects to educate the public about hydrogen safety and fuel cells, and they have supported hydrogen safety experiments and demonstrations. This work should be continued and expanded.

8. Conclusions

We come to the following major conclusions:

<u>On Hydrogen Infrastructure:</u>

1. A distributed hydrogen fueling infrastructure based on reforming natural gas at the fueling station would not only be affordable, but has the potential to cost as much as 28% less than the annual cost of maintaining the existing crude oil-to-gasoline fuel supply system.
2. Adding a distributed hydrogen fuel infrastructure to support fuel cell vehicle has the potential to reduce global motor vehicle fuel infrastructure costs by US$840 billion to US$1.1 trillion over the next 40 years, since hydrogen from natural gas requires less investment than gasoline from crude oil.
3. The cost to place a small-scale steam methane reformer systems at 10% of all California gasoline stations would be less than $200 million, and the cost to install hydrogen fueling appliances at 10% of all stations nationwide would be less than $2 billion.
4. A one-cent/gallon gasoline tax increase as part of a feebate system would provide $1.3 billion per year in revenue, enough to purchase and install 6,500 hydrogen fueling appliances per year. Within two years, this new tax feebate would pay for installing hydrogen fueling appliances at more than 10% of all major gasoline stations in the US.
5. The cost of hydrogen made by steam reforming of natural gas at the fueling station and used in a direct hydrogen fuel cell vehicle is projected to be competitive with gasoline per mile driven in a conventional car.
6. Introducing fuel cell vehicles powered by hydrogen made from natural gas has the potential to decrease global oil consumption by up to 1,000 quads over the next 40 years as conventional gasoline cars and diesel buses are replaced with fuel cell vehicles.
7. Natural gas resources would be decreased by at most 8% to 11% by 2040 if all hydrogen for fuel cell vehicles were derived from natural gas; to the degree that renewable hydrogen supplants hydrogen from natural gas, the impact would be even less.

<u>On Hydrogen Onboard Storage:</u>

1. Hydrogen compressed to 5,000 psi or more can be safely stored onboard fuel cell vehicles using carbon fiber-wrapped composite tanks without encroaching on vehicle trunk space.
2. Advanced developments such as storing hydrogen in carbon nanofibers could be beneficial, but no breakthroughs are required for a viable fuel cell vehicle.

On Hydrogen Safety:

1. Outdoors, hydrogen stored in super strong carbon fiber tanks would be less risky than gasoline in plastic tanks.
2. Inside a home garage, hydrogen could very well be less dangerous than gasoline, based on the analogy of natural gas having a demonstrated four times lower fatality rate than propane[35] when used for home heating.
3. Public perception of hydrogen safety based on the hydrogen bomb or the Hindenburg is inappropriate, but must be overcome through education and a positive industry safety record.

On a Transition Strategy:

1. A viable transition strategy would use hydrogen from natural gas as the bridge fuel between today's heavily reliance on imported oil to a renewable hydrogen future.
2. This transition would have five elements:
    a. Deployment of stationary PEM fuel cells running on natural gas for distributed electrical power generation.
    b. Cogeneration of hydrogen from these stationary fuel cell systems.
    c. Limited deployment of electrolyzers to support small fleets of less than 50 fuel cell vehicles
    d. Introduction of small-scale natural gas reformers at local fueling stations to supply hydrogen as needed for fuel cell vehicle fleets
    e. As renewable energy sources became economically competitive in any region, renewable hydrogen would replace hydrogen from natural gas.
3. This transition strategy would provide better interim security and lower pollution and greenhouse gas emissions than the alternatives.
4. This hydrogen from natural gas strategy would be economically self-sustaining after the initial government investments.

[35] That is, hydrogen is similar to natural gas (lighter than air and a better lower flammability limit above 4%), and gasoline is similar to propane (heavier than air and lower flammability limit near 1%). By analogy, since natural gas is four times less risky than propane in the home based on historical fire data, then hydrogen may be less risky than gasoline in a home garage.

Acknowledgments

Most of the analyses reported here were originally conducted when current H_2Gen employees worked at Directed Technologies, Inc. of Arlington Virginia. Ira F. Kuhn, Jr, the President of DTI, was one of the first to show through detailed analyses in the late 1980's and early 1990's that PEM fuel cells could economically replace the internal combustion engine. We acknowledge his vision and dedication to the development of hydrogen and fuel cell vehicles over the years. We also thank the U.S. Department of Energy and the Ford Motor Company for their support of much of our work over the last decade. Brad Bates, Ron Sims, Jim Adams, and George Saloka among others at Ford provided the technical leadership for the fuel cell vehicle development program. The DOE's Office of Transportation Technology under Pandit Patil and Steve Chalk funded the multiyear contract with the Ford Motor Company to develop direct hydrogen fuel cell vehicles, leading to the detailed evaluations of onboard hydrogen storage, hydrogen infrastructure and hydrogen safety studies, some of which is summarized here. The Hydrogen Program Office under DOE's Office of Power Technology led by Sig Gronich and Neil Rossmeissl have also funded a series of hydrogen system studies while we were employed at DTI, including many of the analyses reported here. None of this work would have been possible without this DOE support.

We are also grateful to Ira Kuhn for supporting the initial research into small-scale steam methane reformers under DTI's internal IR&D funding, research led by Dr. Frank Lomax. We acknowledge the support of George Baum, Brian James and John Lettow of DTI, as well as Erik Bue, Jonathan Ho, Frank Lomax and Stephen Waide, who previously worked for DTI and are now employed by H_2Gen Innovations, Inc..

Appendix A – Nuclear Fusion

Nuclear fusion is the process that fuels the sun. Nuclear fusion is the diametric opposite of nuclear fission, the process used in all existing nuclear power plants. Fusion *combines* or fuses the lightest elements in the universe, such as deuterium and tritium, the isotopes[36] of hydrogen, to form helium, an inert gas. Fission splits apart some of the largest elements such as uranium or plutonium, creating a witches brew of radioactive waste products in the process.

If a fusion reaction could be controlled to produce electricity (or hydrogen), it would be essentially sustainable. A fusion reactor would have the following attributes that are for the most part the exact opposite of existing fission reactors. A fusion reactor would:

- Produce no radioactive fuel waste[37] – the deuterium-tritium reaction produces helium gas, a commercially useful gas that will become scarce as natural gas production declines in the future (helium is now produced as a by-product of natural gas extraction.)
- Generate no bomb-grade materials or other weapons proliferation concerns.
- Have no possibility of a runaway reaction – only enough deuterium and tritium would be injected into the reactor vessel to sustain the designed power level—no critical mass is required to sustain a fusion reaction.
- Be sustainable by extracting deuterium and lithium from sea water. – the lithium would be converted to tritium in the fusion reactor.
- Generate no local air criteria pollutants and no greenhouse gas emission in operation.[38]

Thus nuclear fusion would be a sustainable energy option – it would produce no environmental degradation in operation, and it would consume no non-renewable natural resources[39]. However, controlling a thermonuclear reaction has proven very elusive over the last five decades. Hundreds of millions of dollars have been spent each year trying to perfect two separate methods of controlling a fusion reaction: magnetic confinement fusion, where exceptionally strong magnetic fields are used to contain the reaction, and inertial confinement fusion where extremely powerful laser or particle beams are used to implode pellets containing tritium and deuterium, the primary fusion fuel ingredients. To date scientists have not been able to reach scientific breakeven, where the fusion energy produced by the reaction is equal to the energy put into the reaction. But even if scientific breakeven could be demonstrated, engineers would still have to design, build and test reactors that could produce a net increase in energy at an affordable cost. In the 1960's and 1970's

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[36] An isotope of an element contains a different number of neutrons than the basic element. Since conventional chemistry depends primarily on the number of electrons in the outer shell of an atom, all isotopes of an element behave chemically almost the same. Thus a hydrogen atom contains no neutrons – just one proton and one electron. Deuterium, the first isotope of hydrogen contains one neutron, while tritium, the second isotope of hydrogen contains two neutrons. But chemically all three have but one electron, and behave in a similar fashion in any chemical reaction.
[37] While the fusion reaction would produce no radioactive waste from the fuel stream, the energetic 14 MeV neutrons from the DT reaction will irradiate the reactor itself plus the cooling medium surrounding the reactor. Thus the reactor itself would become highly radioactive and would have to be protected for hundred or thousands of years.
[38] Some pollution and some greenhouse gases would be generated in the process of constructing a fusion reactor. However, these emissions should be negligible compared to the emissions created during operation over the lifetime of coal-fired or even natural gas-fired conventional power plants.
[39] Technically the deuterium and lithium in seawater are not renewable, but are virtually inexhaustible on a millions of years' time scale.

many scientists predicted that fusion energy would be harnessed within 20 to 30 years. Now, 30 to 40 years later, we seem no closer to achieving a practical fusion reactor, and the 1970's prediction of 20 to 30 more years now seems even more optimistic despite the passage of time.

Appendix B - Potential Impact of Fuel Cell Vehicles on Natural Gas Supply

One key issue for large-scale deployment of fuel cell vehicles running on hydrogen derived from natural gas is the long-term impact on natural gas resources. The added consumption of natural gas will depend on the number of FCVs introduced over time. We first estimate a likely range of FCV market penetration, and then compare the resulting natural gas demand with projected natural gas resources over the next 40 years.

B-1. Fuel Cell Vehicle Market Penetration Scenarios

For several years DaimlerChrysler has predicted that they would sell 40,000 FCVs by 2004, presumably driven by the California ZEV mandate that originally called for 10% of all new cars offered for sale in California to be zero emission vehicles by 2003. Now, however, it seems unlikely that anything more than a few hundred FCVs would be on the road by 2004, most of them test vehicles or in tightly controlled fleets. More recently, the California Fuel Cell Partnership looked at scenarios that envisioned 40,000 FCVs on the road by 2010. But the Partnership issued a report without any particular date for reaching the 40,000-vehicle milestone.

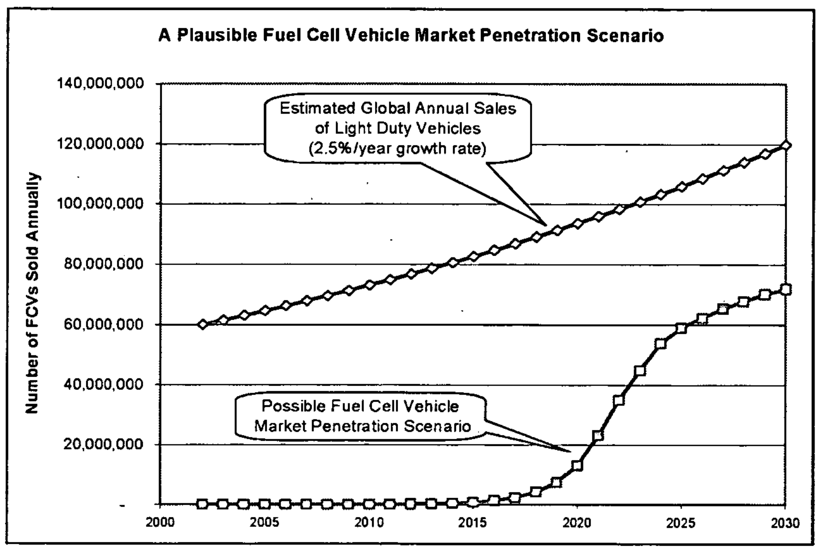

Figure B-1. One possible fuel cell vehicle market penetration scenario,

Based on the current outlook, we have postulated the FCV sales projections shown in Figure B-1. We assume that the global light duty vehicle sales grow 2.5% per year from the current levels of 60 million sales per year. We then postulate that 40,000 FCV are sold by 2010, reaching 60% of all sales by 2030 and continuing at the 60% level thereafter.

For clarification of the sales in the early years, we also show a logarithmic plot of the same data in Figure B-2. One million FCVs are sold by 2015, which implies something like three auto companies each with a modern 300,000-car per year plant producing FCVs. Sales of FCVs reach 10 million by 2020, indicating that the major car companies have more than one model line of FCVs for sale such as one or more passenger vehicles and a FCV SUV, etc.

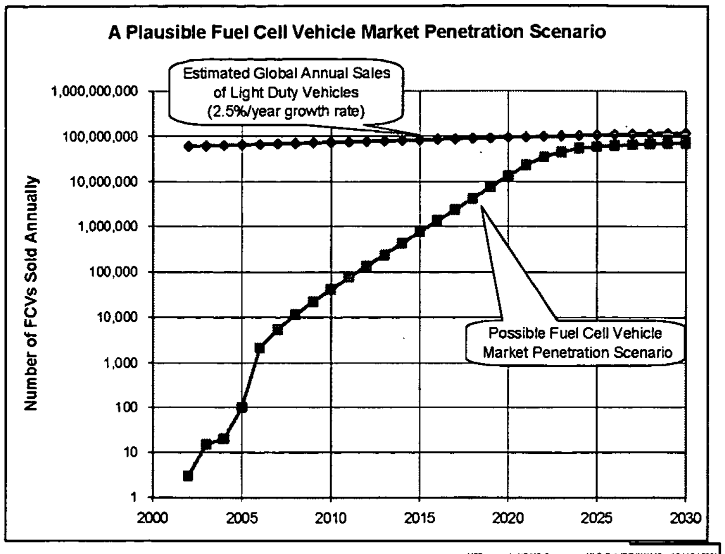

Figure B-2. Log plot of the plausible FCV market scenario

We have also postulated an upper bound, highly optimistic FCV market penetration scenario (Figure B-3). In this case the mass production takes off immediately, reaching annual sales of 40,000 by 2007 and 900,000 (three production lines) by 2010, and capturing 80% of the global market by 2030 and thereafter. This scenario is probably too optimistic on both the achievement of 40,000 sales by 2007 as well as the capture of 80% of all sales by 2030. We believe that these two FCV market penetration scenarios capture the likely extremes, and should represent an upper and lower bound for projecting natural gas requirements for FCVs.

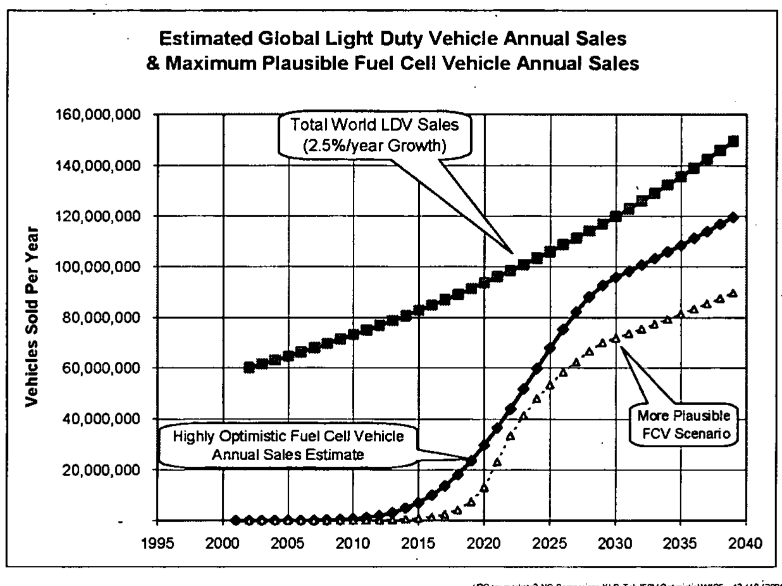

Figure B-3. Illustration of a maximum plausible FCV market penetration scenario

For clarity in the early years, these FCV sales data for the optimistic case are replotted in Figure B-4 with a logarithmic scale.

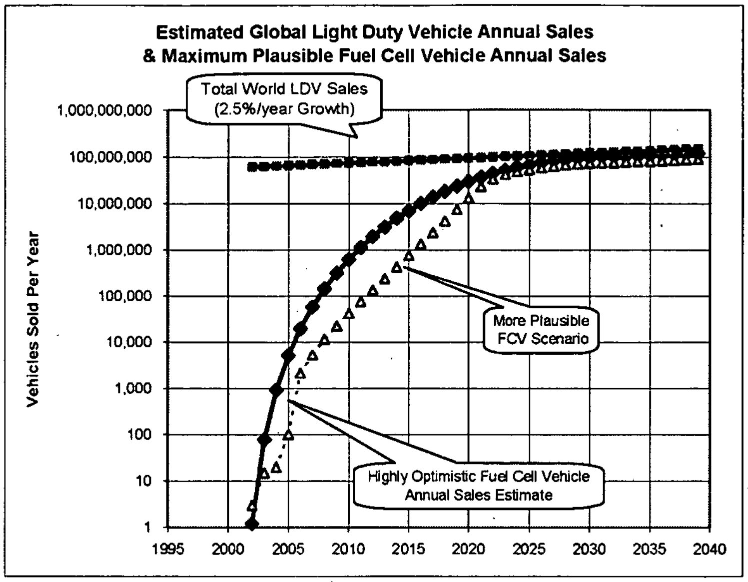

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Figure B-4. The number of fuel cell vehicle sold annually for two FCV scenarios on a log plot

B-2. Natural Gas Consumption

Given these two FCV market penetration scenarios, we can now calculate how much natural gas would be required, assuming that all FCVs are run on hydrogen derived from natural gas. We made the following assumptions:

- Average FCV lifetime: 12 years (determines cumulative number of FCVs on the road in any given year)
- Average FCV miles traveled per year: 13,000
- Average FCV fuel economy: 50 mpgge[40]
- Natural gas reformer net efficiency[41]: 72%

With these assumptions, the postulated fleet of FCVs would consume between 43 and 60 quads of natural gas per year by 2040, as shown in Figure B-5. While this amount of natural gas may seem high compared to current consumption (the US consumed 23.4 quads of natural gas in 2000), it is not large compared to future natural gas consumption projections. In addition, these projections are for the world motor vehicle fleet. World natural gas consumption was 87 quads in 1999. More

[40] The FCV fuel economy is measured in miles per gallon of gasoline equivalent (mpgge). Thus a FCV with 50 mpgge fuel economy would travel 50 miles on the amount of hydrogen with a lower heating value equal to that in one gallon of gasoline. The 50 mpgge is based on an estimated average of passenger vehicles and light duty trucks. Thus passenger vehicles are projected to have 65 to 70 mpgge for a mature FCV, while SUVs and light duty trucks would bring the average to the 50 mpgge range.

[41] The natural gas reformer efficiency is defined as the lower heating value of hydrogen produced divided by the lower heating value of natural gas into the reformer. This efficiency does not include the electricity needed to run the reformer, so the net system efficiency including electricity would be less than 72%.

importantly, global natural gas consumption is projected to grow to 168 quads by 2020, and, if we extrapolate to 2040 with the IEO 2001 world rate of growth of 2.3% per year from 2019 – the last year in their projection, then the world would be consuming 300 quads of natural gas. Thus FCVs would increase natural gas consumption by 15% in 2040 based on the more realistic FCV market penetration scenario, or by at most 20% in the most optimistic FCV penetration case.

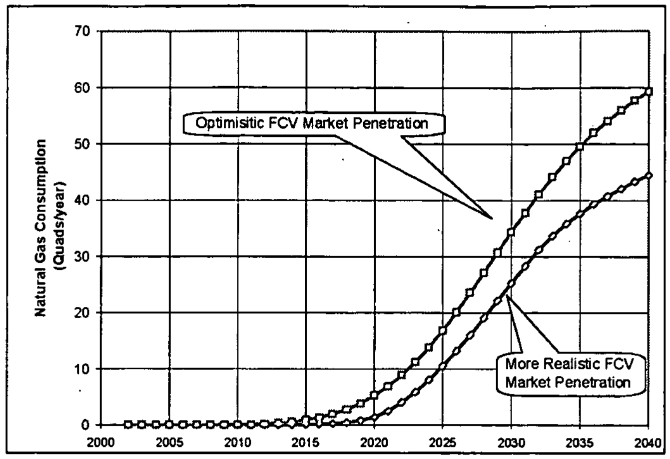


Figure B-5. Estimated natural gas consumption to support all fuel cell vehicles

Another way to evaluate the impact of FCVs on natural gas consumption is to compare the FCV natural gas consumption with the projected *increases* in natural gas consumption without FCVs. This result is plotted in Figure B-6, showing that FCV natural gas consumption is less than 30% of the projected increases in total natural gas consumption without FCVs.

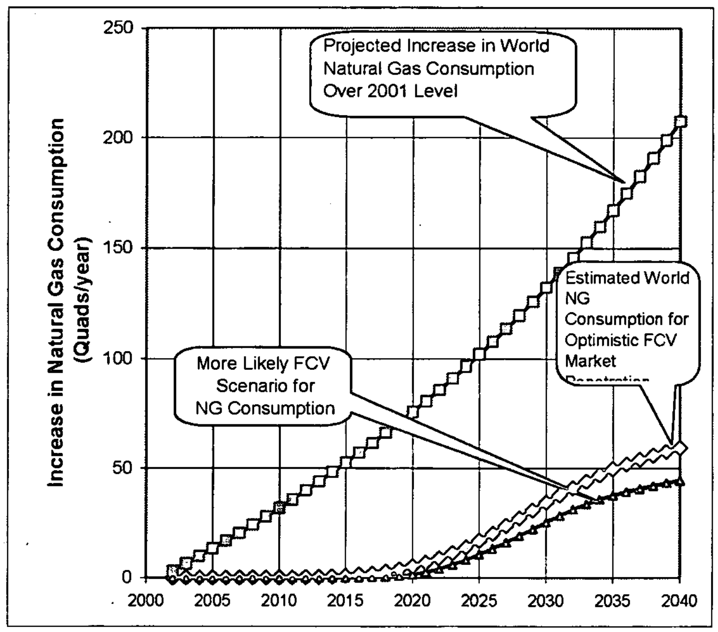


Figure B-6. Comparison of FCV natural gas consumption with projected increases in global natural gas consumption over 2001 level.

The natural gas consumed by FCVs is also plotted in Figure B-7 as a fraction of the increased demand for natural gas from other users. Note also that the fractional impact reaches a peak the 2035 time period as FCV begins to saturate the world's automobile fleet. After that the fractional impact declines, since we are assuming here that motor vehicle grows at 2.5%/year, while natural gas consumption (without FCVs) grows at 2.9%/year, the EIA estimated growth rate for 2019.

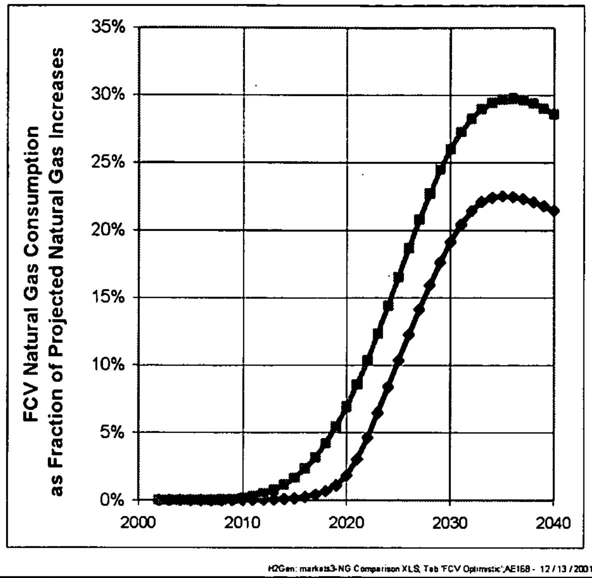


Figure B-7. Fuel cell vehicle natural gas consumption as a fraction of the increased demand for natural gas from other end users

B-3. Impact of FCVs on Natural Gas Reserves

The cumulative consumption of natural gas over the next four decades is shown in Figure B-8 for the two FCV scenarios. Total natural gas requirements would be between 500 and 700 quads under these projections. This assumes no substitution of other sources of hydrogen over the next 40 years. But we expect that renewable energy will begin to generate hydrogen as fossil fuel costs inevitably increase due to some combination of scarcity, increased cost of discovery and extraction, and the imposition of some form of carbon tax or other method of accounting for the externalities of fossil fuel consumption. For example, hydrogen from wind energy electrolysis could supplement hydrogen from natural gas in the Midwest in the next decade. Hydrogen from PV energy electrolysis in the Southwest could be economic within two to three decades. And hydrogen might be produced economically by gasifying fast-growing energy crops such as switchgrass in the

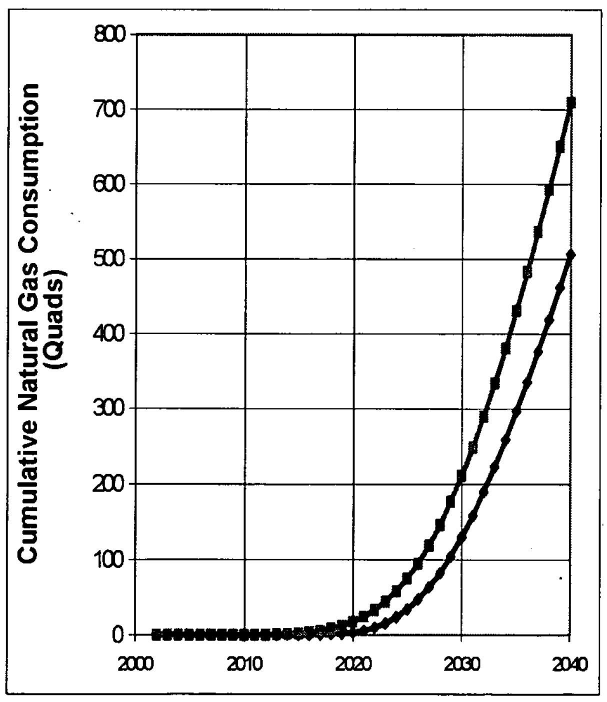


Figure B-8. Cumulative natural gas consumption over 40 years for the two FCV market penetration scenarios

Southeast or Midwest. Hydrogen could also be produced by gasifying municipal solid waste (MSW). Joan Ogden of Princeton University estimates that converting all MSW to hydrogen would produce enough fuel for one third of all motor vehicles. Introduction of these renewable hydrogen sources would decrease the projected natural gas consumption indicated in Figure B-8.

Cumulative consumption of 500 quads of natural gas for FCVs represents approximately 10% of current proven world reserves of natural gas, estimated at 5,200 quads[42]. The total cumulative consumption of natural gas for all other uses (excluding FCVs) over the next 40 years would be 7,300 quads at the projected rate of growth.. Of course this does not imply that we will run out of natural gas in 29 years, since more proven reserves are discovered each year. Proven reserves have increased significantly each year despite increased consumption each year – the gas industry continues to discover more gas or render more gas recoverable than we consume. Proven world reserves increased from 2,490 quads in 1975 to today's estimates of 5,200 quads. This cannot increase indefinitely, however, since there is a finite amount of gas available in the Earth's crust.

Ideally we would like an estimate of total recoverable natural gas reserves so that we could judge the impact of adding FCVs running on hydrogen from natural gas. In the U.S., for example, the proven reserves amount to an estimated 13% of technically recoverable natural gas, or approximately 170 quads out of a total estimated recoverable resources of 1,280 quads[43]. These other recoverable resources include other unproved reserves (13%), undiscovered nonassociated gas (25%), inferred nonassociated gas (19%) and unconventional sources (31% including tight gas, Devonian shale, and coalbed methane.)[44] If we applied this 13% factor to the global proven reserves, one might infer total natural gas recoverable resources on the order of 40,000 quads. On this basis, the projected natural gas consumption (excluding FCVs) through 2040 of 7,200 quads would represent 18% of all currently projected recoverable reserves. Supplying FCVs with hydrogen from natural gas would then increase global consumption over the next 40 years by 500 to 700 quads, representing 1.25% to 1.75% of total recoverable natural gas resources. These estimates of unconventional sources are highly speculative, of course, since we do not know if they could be economically recovered.

B-4. Natural Gas vs. Crude Oil Consumption

Excluding unconventional natural gas sources, the EIA estimates a global resource base of 15,000 quads, of which we have consumed just under 10% to date, leaving an estimated 13,500 quads of proven reserves, reserve growth and undiscovered natural gas resources[45]. For comparison, they estimate that the original crude oil base before any extraction was about 18,100 quads. However, we have already consumed just under 25% of the estimated oil base, leaving 13,200 quads of conventional crude oil deposits. In other words, the EIA estimates that our crude oil net conventional resources are slightly less than our global natural gas resources. Since the world is consuming crude oil at a faster rate than natural gas (152 quads/year for oil vs. 87 quads/year for

[42] "World natural gas reserves," Canadian Statistics, November 12, 2001 http://www.statcan.ca/english/Pgdb/Economy/Primary.prim32.htm

[43] Energy Information Administration, "US Natural Gas Markets: Recent Trends and Prospects for the Future," May 2001, pg. 34.

[44] These estimates do NOT include natural gas hydrates, which are estimated to contain more energy in the ocean bottoms than all other fossil fuels combined. If the gas industry develops a method for safely and economically tapping into natural gas hydrates, then FCV usage would be negligible compared to the resource.

[45] Energy Information Administration, "International Energy Outlook 2001: Natural Gas, pg. 47.

natural gas in 1999), this would indicate that we could expand natural gas consumption much more readily than crude oil consumption without running short on either in the next four or five decades.

We have attempted to illustrate the effects of adding fuel cell vehicles to the total resources of natural gas and crude oil. Each FCV sold will remove one ICEV from the road and will reduce the consumption of crude oil. Since total crude oil resources (proven reserves plus reserve growth plus undiscovered oil) are slightly less than natural gas global resources, and since we are consuming crude oil faster than natural gas, saving crude oil by displacing gasoline-powered cars should be more valuable to society over time than increasing consumption of natural gas. We assume here that the LDV fuel cell fleet has an average fuel economy of 50 mpgge, while the fleet average for ICEVs is 25 mpg. This is probably too generous for ICEVs, since EIA projects a fleet average fuel economy of only 21.0 mpg by 2020. In addition, our vehicle simulations predict a 2.2 times better fuel economy for FCVs than ICEV under realistic driving conditions, such that a 50 mpgge FCV fleet average would imply a 22.7 mpg ICEV fleet average. But even with these conservative assumptions, the savings in crude oil consumption are larger than the increased natural gas consumption. Over the next 40 years, natural gas consumption would be increased by a total of 500 to 700 quads by the introduction of FCVs, while crude oil consumption would be *decreased* by 700 to 1,000 quads. Total fossil fuel consumption would therefore be reduced by 200 to 300 quads over 40 years due to direct hydrogen FCVs introduced according to our two scenarios.

Not only would FCVs reduce net energy consumption, but they would favorably redistribute consumption from the most scarce resource (crude oil) to the more plentiful resource (natural gas), as illustrated by Figure B-9. These curves were generated by extrapolating the EIA world consumption estimates from the 1995 to 2020 period out to 2040[46]. This assumes that no additional reserves are found over and above the predicted reserve growths and undiscovered but recoverable estimates for both crude oil and for natural gas. By 2040, crude oil would be 26% to 36% higher with the introduction of FCVs, while natural gas would be 8% to 11% lower.

[46] The model extrapolates based on the rate of growth estimated by EIA for the last year of their projection, 2019, not the average annual growth over the 1995-2020 time period. Thus, for natural gas, the average growth over the period was 3.21%, but by 2019 the growth rate slowed to 2.93%. We assumed here that natural gas growth continued at a 2.93%/year rate from 2020 to 2040. Similarly for crude oil, the average growth rate was 2.28%, but the consumption grew slightly to 2.34%/year by 2019. We used the 2.34%/year rate for the 2020 to 2040 period.

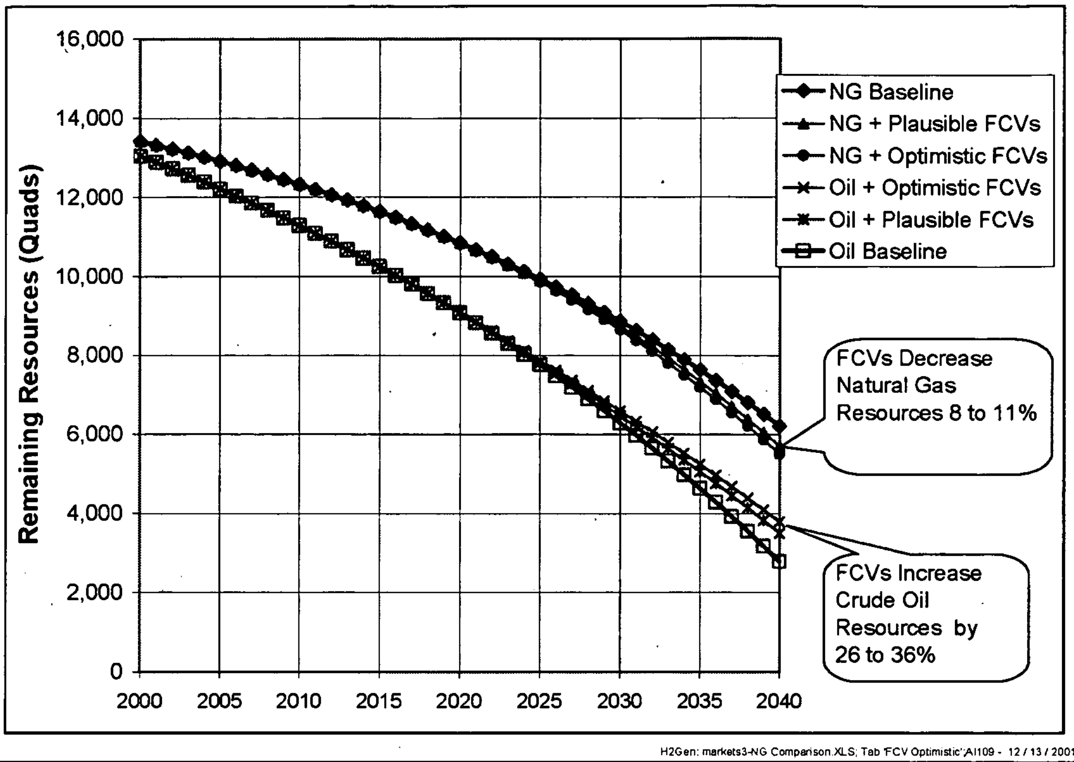


Figure B-9. Comparison of the impact of fuel cell vehicles on the estimated natural gas and crude oil resources over the next 40 years.

B-5. Conclusions Regarding Long-Range Natural Gas Resources

We conclude that the introduction of fuel cell vehicles powered by hydrogen derived from natural gas would have the following long-term global consequences on fossil fuel resources:

1. Total fossil fuel consumption would be reduced by 200 to 300 quads over the next 40 years as gasoline-powered cars were displaced by more efficient hydrogen-powered fuel cell vehicles. Crude oil consumption would decrease by 700 to 1,000 quads, while natural gas consumption would increase by 500 to 700 quads, depending on fuel cell vehicle market penetration rates.
2. The imbalance between crude oil and natural gas total recoverable resources would be partially restored, as crude oil--the scarce asset by 2040--would be increased with FCVs, while natural gas--projected to be the more plentiful resource-- would be reduced.
3. Total recoverable natural gas reserves would be reduced between 8% and 11% by 2040, which would correspond to at most a two-year acceleration of natural gas depletion.
4. Natural gas for FCVs would increase the growth in global natural gas consumption previously projected by EIA (without FCVs) by as much as 30% by 2035, falling off to lower fractions of projected increases thereafter – other uses for natural gas are predicted to grow slightly faster than motor vehicle growth.

Overall, this assessment illustrates that there should be ample global natural gas resources to support a very robust direct hydrogen fuel cell vehicle program for at least 40 years. Presumably much of the hydrogen would be generated by renewable sources by that time if not sooner, reducing the impact of FCVs on natural gas reserves. Regional differences abound, and the local cost for natural gas may vary considerably over time and region. Future analyses should explore regional differences and the likely cost implications of increasing natural gas consumption for fuel cell vehicles.

Appendix C – Total Fuel Infrastructure Cost: Gasoline vs. Hydrogen

Commentators have previously focused almost exclusively on the initial incremental cost of adding a hydrogen infrastructure system. This overlooks the enormous costs of maintaining the existing crude oil to gasoline fuel system. Every year the oil industry must spend hundreds of billions of dollars to explore for new oil fields; to sink new wells and extract more oil to replace the output from declining wells; to maintain old and build new crude oil and product pipelines, to maintain and expand oil refineries, and to maintain the gasoline delivery systems. As new FCVs running on hydrogen from natural gas begin to replace ICEVs, these oil industry investments can be gradually reduced. In principle an oil company could divert investments from oil to natural gas as the FCV revolution proceeds while continuing to earn reasonable return on their investments.

While very early FCV fleet introductions can utilize the existing natural gas infrastructure, eventually additional investments will be required to explore for and extract more natural gas. We therefore need to compare the costs of producing and delivering gasoline from crude oil with the costs of producing and delivering hydrogen from natural gas to the end user.

The oil and gas industry investments can be divided into four separate endeavors:

1. Exploration and Development (E&D)
2. Extraction or "Lifting Costs"
3. Fuel Processing (gas processing for natural gas and refineries for crude oil)
4. Transportation, Storage & Delivery

In the following sections we estimate current investments required in each of these four sectors, with emphasis on the cost differences between crude oil and natural gas.

C-1. Exploration and Development Costs

Exploration and development (E&D) investments are not separated between crude oil and natural gas. An oil company searches for fossil fuel deposits, and generally is not sure a priori of the fractional split between oil and gas in any given field. The costs for exploration and development of a field do not vary considerably if one is prospecting for oil vs. gas.

The EIA provides estimates of "finding costs," defined as the total E&D costs divided by the barrels of oil equivalent (BOE[47]) of added reserves as a result of the E&D efforts. The EIA[48] estimates that the finding costs in the US for oil and gas averaged $6.47/BOE for the 1996 to 1998 and $6.72/BOE for the 1997 to 1999 time period, or an average of $6.60/BOE, or $1.13/MBTU-HHV.[49]

[47] BOE = barrels of crude oil equivalent. Natural gas is converted to BOE by the factor of 0.178 BOE per 1,000 scf of natural gas, or one scf of natural gas = 1,041 BTU-HHV.
[48] *Performance Profiles of Major Energy Producers 1999.* Energy Information Administration, U. S. Department of Energy, Table 20, page 60, January 2001.
[49] One barrel of crude oil is assumed to contain 5.85 MBTU-HHV of energy.

The E&D costs vary over time, as shown in Figure C-1. This figure plots the E&D costs averaged over three years (current year plus two previous years) divided by the current year production instead of dividing by added reserves that is used in the EIA "finding cost" numbers. Since more reserves are added each year than are produced, this measure of E&D costs will be higher than the "finding costs" that have the larger added reserves as the denominator. In any case, we will use the smaller \$6.60/BOE in calculations below of average savings from reduced total fossil fuel consumption with fuel cell vehicles. While E&D costs were lower in the 1988-1996 time period, costs for finding new oil and gas in the future should in general increase.

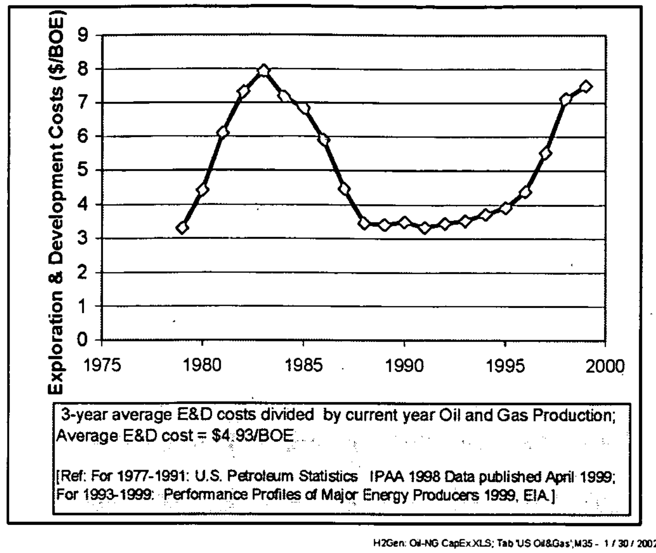


Figure C-1. Variation in oil and gas exploration and development costs

C-2. Fossil Fuel Extraction Costs

The costs of extracting or "lifting" fossil fuels do differ for crude oil and natural gas. In general crude oil costs about 2.5 times more to lift than natural gas per MBTU of fuel extracted. The EIA estimates the following costs (Table C-1) for onshore and offshore oil and gas lifting in the US [50]:

Table C-1. Estimated average lifting costs for oil and gas in the US (\$/BOE), based on average of 1990-1999.

	Onshore	Offshore	Weighted Average[51]
Oil	7.50	6.00	7.15
Natural Gas	3.00	2.50	2.87

C-3. Fuel Processing Costs

Processing crude oil into its many products (including gasoline) is much more expensive than processing wet natural gas (methane plus other hydrocarbons) into "dry" natural gas that is mostly methane. In addition, most natural gas processing plants generate liquid fuels (natural gas liquids – NGL) that typically account for 20% of all liquid fuels delivered. So some costs associated with operating and maintaining the 640 natural gas processing plants in the US actually produce liquid fuels, not dry natural gas. Thus some of the costs associated with processing natural gas actually yield increased liquid fuels that we generally associate with petroleum liquid products.

[50] *The Majors' Shift to Natural Gas.* Energy Information Administration, U. S. Department of Energy, Figures 14a and 14b, page 15, September 2001.

[51] The weighting between onshore and offshore is based on data in Table B25 for 1999, on pg.105 of EIA-January 2001, when the industry produced 23.5% of crude oil offshore and 27% of natural gas offshore.

C-3.1. Oil Refinery Capital Investments

The EIA estimates that the oil refining operation adds approximately $5.14/BOE to the cost of gasoline ($2.75/BOE for energy, $0.54/BOE for other operating expenses, and $1.85/BOE for new capital investments.)[52] This is a US average based on the EIA 2002 Annual Energy Outlook database in year 2000 dollars. This estimate of $1.85/BOE for new capital investments is greater than the "additions to Property, Plant and Equipment" (PP&E) reported by EIA for the FRS[53] companies that averaged $1.39/BOE for refining/marketing of oil products over the 1993-2000 time period. We use the higher estimate in this report.

C-3.2. Natural Gas Processing Plant Capital Investments

Natural gas processing plant costs are more difficult to estimate. Processing costs vary widely depending on the quality of the natural gas. The gas from some fields requires little more than water removal. Other wells produce gas that includes liquid hydrocarbons, carbon dioxide, nitrogen, sulfur and other contaminants that must be removed at the processing plant. Phillips Petroleum reported one set of data for their GPM (natural gas gathering, processing and marketing) operation for 1998 and 1999, as summarized in Table C-2. This Phillips division includes 16 processing plants and 29,000 miles of gathering pipelines, so these cost data should be a reasonable average representative of the natural gas industry.

Table C-2 Cost and production data from Phillips Petroleum GPM natural gas gathering and processing division

	1998	1999	Average	Quads/year
Capital Investments	$47M	$124M	$85.5M	
NG Liquids (bbl/day)	157,000	156,000	156,500	0.33
Raw Natural Gas (Million cf/day)	1,847	1,758	1,800	0.68

Natural gas accounts for 67.3% of the BTU output of these processing plants. If we attribute 67.3% of the capital expenditures to the natural gas product averaged over the two years, then the plants require investments equivalent to 8.46 cents/MBTU of natural gas produced. This is equivalent to $0.50/BOE, or 3.7 times less costly per BTU than an oil refinery. The American Gas Association reports even lower capital investments for natural gas "production and storage", averaging $500 million over the last 10 years to produce , which is equivalent to only 3.3 cents/MBTU[54]. We use the higher value from the Phillips data to be conservative.

C-4. Pipeline & Transport Capital Investments

Both natural gas and oil require investments in pipelines and other transport to bring the product to market. Pressurized natural gas pipelines are more expensive than crude oil or refined product pipelines, and, unlike gasoline, natural gas cannot be delivered economically by tanker trucks.

[52] Private communication with Han-Lin Lee, Operations Research Analyst, Office of Integrated Analysis and Forecasting, Oil and Gas Division, Energy Information Administration, January 31, 2002.

[53] FRS = financial reporting system, referring to companies required to submit form EIA-28 to the DOE; these companies account for approximately 45% of all US natural gas and oil production.

[54] P. Wilkinson, D. Shin, and P. Pierson: *Gas Facts: A Statistical Record of the Gas Industry: 1999 Data,* American Gas Association, Washington, D. C. 2000.

Thus total transportation costs for natural gas are higher than gasoline delivery costs. Expenditures for natural gas pipelines have been extremely erratic over the years for the FRS companies, as shown in Figure C-2. The average annual US natural gas pipeline capital equipment investments over the 1979-2000 time period has been $1.21 billion per year. The average crude oil and natural gas liquids pipeline capital expenditures were $300 million/year, and the average refined produce investment was $157 million per year, or a total of $457 million/year for crude oil/gasoline. However, the FRS companies account for only 45% of total US oil & gas production, so the total US costs for regulated pipelines are estimated at $2.69 billion per year for natural gas pipelines and $1.02 billion per year for crude oil and gasoline pipelines.

The average annual production of these two fuels for the 1979-2000 time period were 16.2 quads of oil per year and 19.6 quads of natural gas per year. The rate of pipeline capital expenditures are therefore $0.80/BOE for natural gas and $0.37/BOE for crude oil and gasoline.

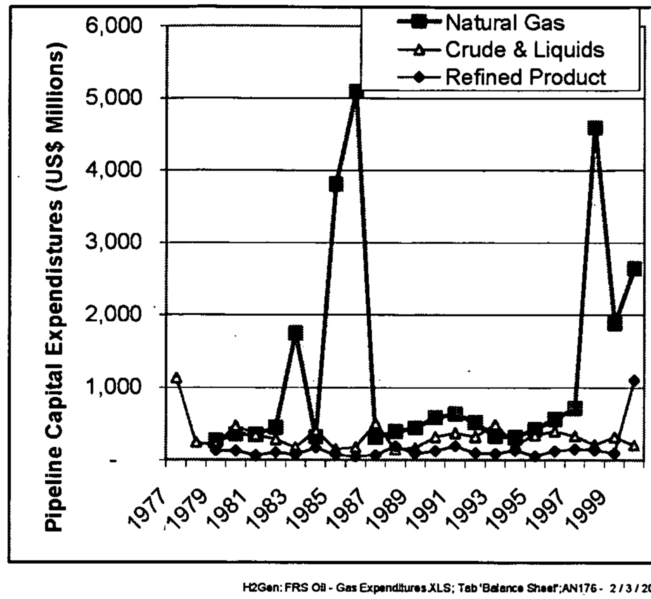


Figure C-2. Variation in US natural gas pipeline costs over time

C-5. Summary of Estimated Oil & Gas Expenditures

The total costs per barrel of oil equivalent for oil and gas operations are summarized in Table C-3.

Table C-3. Estimated expenditures for fossil fuel production per unit energy produced ($/BOE)

	Natural Gas	Crude Oil
Exploration & Development	6.73	6.73
Lifting Costs	2.87	7.15
Fuel Gathering & Processing	0.50	1.85
Pipeline & Transport	0.80	0.37
Totals	10.90	16.10

Thus for every BOE equivalent of natural gas produced instead of crude oil, the oil and gas companies need to invest $5.20/BOE less or a $0.89/MBTU net fuel infrastructure cost reduction.

C-6. Hydrogen Fueling Station Investment Costs

The natural gas investment costs estimated above will pay for the infrastructure to bring natural gas to the local fueling station. To this must be added the cost of installing hydrogen fueling appliances (HFAs) at the local fueling station to convert the natural gas to hydrogen, to compress that hydrogen

to the 7,000 to 8,000 psi range to fill 5,000 psi car tanks, and to store and dispense the hydrogen into FCVs. These onsite hydrogen infrastructure costs will depend on the size of the fueling station and fueling appliance manufacturing volume. For modest production volumes (100-200 per year), we estimate the costs summarized in Table C-4 for two different fueling appliances based on the proprietary H_2Gen HGM fuel processor. The initial HFA[55] would be sold to fleet operators, bus garages and public fueling stations when their were less than 160 FCVs filling up with hydrogen at a given station. As FCV sales increased, multiple HFAs could be installed. In a mature market, the larger HFA would be used to more economically fill FCVs with hydrogen. We fully expect that costs of the HFA will decrease with higher volume production, but we have used the $530/FCV estimate throughout the 40-year period with a 70% capacity factor for the purposes of this infrastructure cost projection.

Table C-4. Estimated costs for the H_2Gen HFA Hydrogen Fueling Appliance

	Initial Starting Fueling Appliance	Mature Hydrogen Fueling Appliance
Number of FCVs Supported	160	1,440
Number of FCVs fueled/day	20	180
Number of FC Buses Supported	4	36
Fueling Appliance Costs (US$)		
Fuel Processor	$100,000	$425,000
Hydrogen Compressor	$25,000	$125,000
Hydrogen Storage	$31,000	$185,000
Hydrogen Dispenser	$24,000	$25,000
Total HFA Cost	$180,000	$760,000
Cost per FCV Supported	$1,125/FCV	$530/FCV

C-7. Estimated Fuel Infrastructure Savings

Based on these infrastructure costs, we can now estimate the total investment savings over the 40-year time horizon for FCV market introduction. We assume that the hydrogen fueling appliances with a 12-year lifetime are installed in concert with new FCV sales[56]. For every 1,440 FCVs sold, one new HFA must be installed, or an on-site infrastructure cost of $530/FCV sold. From the estimate of crude oil/gasoline investments required of $16.10/BOE, we can assign the total gasoline infrastructure cost over the life of every new ICEV sold. The assumptions for these calculations are summarized in Table C-5.

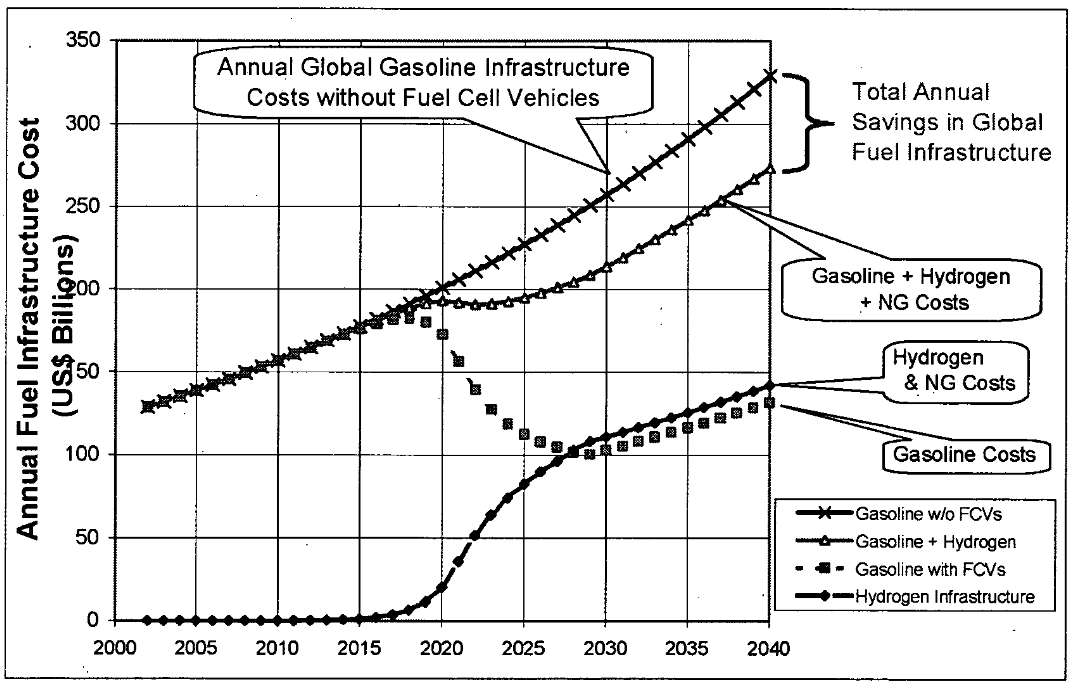
[55] The H_2Gen HFA fueling appliance includes the HGM fuel processor to convert natural gas or propane to hydrogen, a gas purifier to provide at least 99.95% pure hydrogen, a hydrogen compressor, hydrogen storage tanks and a dispenser to fill up FCV fuel tanks.

[56] In reality some components such as the storage vessels, the dispenser and some of the fuel processor components may have longer lifetimes or some salvage/reuse value. We have assumed conservatively here that all HFA components are replaced every 12 years.

Table C-5. Estimated fuel infrastructure investment required for each new fuel cell vehicle and for each new conventional gasoline vehicle sold

	NG/H2 FCV	Crude Oil/Gasoline ICEV
Average Fleet Fuel Economy (mpgge)	50	25
Miles Traveled per year	13,000	13,000
Vehicle Lifetime	12	12
NG reformer efficiency (LHV)	72%	-
Fossil Fuel infrastructure investment ($/BOE)	10.90	16.10
Fossil Fuel infrastructure investment ($/car)	$1,009/FCV	$2,146/ICEV
Onsite H2 NG reformer and fueling appliance	$533/FCV	-
Total Fuel Infrastructure Investment	**$1,542/FCV**	**$2,146/ICEV**

We then calculated the net savings in fuel infrastructure costs as crude oil investments declined and natural gas and HFA investment costs increased over the next 40 years. The estimated fuel infrastructure costs are plotted in Figure C-3 for the next 40 years assuming the plausible FCV market penetration scenario (40,000 FCVs sold globally by 2010, rising to 60% of all new car sales by 2030 and thereafter).



Natural gas + Hydrogen Fueling Appliance Cost =$1542/ FCV
Crude Oil + Gasoline Infrastructure Cost =$2146/ ICEV

H2Gen: markets3-NG Comparison.XLS; Tab 'FCV ';J99 - 2 / 20 / 2002

Figure C-3. Estimated global fuel infrastructure investments with and without fuel cell vehicles for the plausible FCV market penetration scenario

Gasoline infrastructure costs begin to drop significantly after 2017 when 2.3 million FCVs are sold (out of 86 million total sales). Gasoline costs then rise again after 2030 since this model assumes that FCV sales level off at 60% of all LDV sales after 2030—the gasoline ICEVs then rise as the world population of LDVs increases. As shown in Figure C-3, the total cost of gasoline plus hydrogen infrastructures is less than the cost of maintaining the existing gasoline infrastructure in the absence of FCVs. Total annual infrastructure savings reach $55 billion per year by 2040. The total net fuel infrastructure savings from 2003 through 2040 is estimated at $840 billion for this plausible FCV market penetration scenario.

The total natural gas/hydrogen and crude oil/gasoline infrastructure costs are summarized in Table C-6 for both the plausible and the more optimistic FCV market scenarios. With the optimistic scenario, annual infrastructure cost savings reach $74 billion per year by 2040, with a net cumulative savings of $1.1 trillion over the next 40 years.

Table C-6 . Summary of estimated fuel infrastructure costs for the plausible and for the optimistic FCV market penetration scenarios

	Annual Costs in 2040		Cumulative Costs: 2002-2040	
(US$ Billions)	Plausible	Optimistic	Plausible	Optimistic
Natural gas infrastructure cost	92.9	123.8	1,397	1,926
Hydrogen fueling appliance cost	49.0	65.4	738	1,017
Total NG + HFA costs	141.9	189.2	2,135	2,943
Crude Oil Savings	197.5	263.3	2,972	4,097
Net Infrastructure Cost Savings	**55.6**	**74.1**	**837**	**1,153**

NG = Natural gas; HFA = Hydrogen Fueling Appliance; ICEV fleet fuel economy = 25 mpg; FCV fuel economy = 50 mpgge
LDV miles per year = 13000; LDV lifetime = 12 years; HFA cost = $533/FCV; NG Infrastructure =$10.9/BOE
Crude oil/gasoline infrastructure =$16.1/BOE; HGM efficiency = 0.72 [LHV H2 / LHV NG] H2Gen: markets3-NG Comparison.XLS; Tab 'FCV ';J15 - 2 / 20 / 2002